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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
Commission file number: 1-13283

PENN VIRGINIA CORPORATION
(Exact name of registrant as specified in its charter)

Virginia	23-1184320
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Four Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)
Registrant's telephone number, including area code: **(610) 687-8900**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, $0.01 Par Value	**Not Applicable**

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 ("Exchange 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 Exchange Act 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 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 is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of common stock held by non-affiliates of the registrant was $310,407,928 as of June 30, 2015 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and executive officers of the registrant. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 4, 2016, 86,353,944 shares of common stock of the registrant were outstanding.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2015

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Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- our ability to maintain adequate financial liquidity and to access adequate levels of capital on reasonable terms;
- our ability to continue as a going concern;
- our ability to refinance our debt obligations;
- compliance with debt covenants;
- reductions in the borrowing base under our revolving credit facility, or the Revolver;
- our ability to continue to borrow under the Revolver;
- the volatility of commodity prices for oil, natural gas liquids and natural gas;
- our ability to develop, explore for, acquire and replace oil and gas reserves and sustain production;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- any impairments, write-downs or write-offs of our reserves or assets;
- the resumption of our drilling program;
- the projected demand for and supply of oil, natural gas liquids and natural gas;
- our ability to contract for drilling rigs, supplies and services at reasonable costs;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell the production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from estimated proved oil and gas reserves;
- drilling and operating risks;
- our ability to compete effectively against other oil and gas companies;
- our ability to successfully monetize select assets and repay our debt;
- leasehold terms expiring before production can be established;
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key technical employees;
- counterparty risk related to the ability of these parties to meet their future obligations;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties relating to general domestic and international economic and political conditions; and
- other factors set forth in our periodic filings with the Securities and Exchange Commission, including the risks set forth in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2015.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management’s views only as of the date hereof. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

Glossary of Certain Industry Terminology

The following abbreviations, terms and definitions are commonly used in the oil and gas industry and are used within this Annual Report on Form 10-K.

Bbl. A standard barrel of 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

BOE. One barrel of oil equivalent with six thousand cubic feet of natural gas converted to one barrel of crude oil based on the estimated relative energy content.

BOEPD. Barrels of oil equivalent per day.

Borrowing base. The value assigned to a collection of borrower's assets used by lenders to determine an initial and/or continuing amount for loans. In the case of oil and gas exploration and development companies, the borrowing base is generally based on proved developed reserves.

Completion. A process of treating a drilled well, including hydraulic fracturing among other stimulation processes, followed by the installation of permanent equipment for the production of oil or gas.

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.

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. A well found to be incapable of producing either oil or gas in sufficient commercial quantities to justify completion of the well.

Drilling carry. A working interest that will be carried through the drilling and completion of a well.

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, a service well or a stratigraphic test well.

EUR. Estimated ultimate reserves, the sum of reserves remaining as of a given date and cumulative production as of that date.

GAAP. Accounting principles generally accepted in the Unites States of America.

Gas lift. A method of artificial lift that uses an external source of high-pressure gas for supplementing formation gas for lifting the well fluids.

Gross acre or well. An acre or well in which a working interest is owned.

HBP. Held by production is a provision in an oil and gas or mineral lease that perpetuates the leaseholder's right to operate the property as long as the property produces a minimum paying quantity of oil or gas.

Henry Hub. The Erath, Louisiana settlement point price for natural gas.

IP. Initial production, a measurement of a well's production at the outset.

LIBOR. London Interbank Offered Rate.

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

MBOE. One thousand barrels of oil equivalent.

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

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

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units, a measure of energy content.

MMcf. One million cubic feet of natural gas.

Net acre or well. The number of gross acres or wells multiplied by the owned working interest in such gross acres or wells.

NGL. Natural gas liquid.

NYMEX. New York Mercantile Exchange.

NYSE. New York Stock Exchange.

Operator. The entity responsible for the exploration and/or production of a lease or well.

OTC Pink. A marketplace, maintained by the OTC Markets Group, for trading in a wide spectrum of equity securities.

Play. A geological formation with potential oil and gas reserves.

Preferential rights. The rights that nonselling participating parties have in a lease, well or unit to proportionately acquire the interest that a participating party proposes to sell to a third party.

Productive wells. Wells that are not dry holes.

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

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

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

Proved undeveloped reserves. 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. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled.

PV10. Present value of estimated future oil and gas revenues, net of estimated direct expenses, discounted at an annual discount rate of 10%.

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

Revenue interest. An economic interest in production of hydrocarbons from a specified property.

Royalty interest. An interest in the production of a well entitling the owner to a share of production generally free of the costs of exploration, development and production.

SEC. United States Securities and Exchange Commission.

Service well. A well drilled or completed for the purpose of supporting production in an existing field.

Standardized measure. The present value, discounted at 10% per year, of estimated future cash inflows from the production of proved reserves, computed by applying prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), reduced by estimated future development and production costs, computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year (including the settlement of asset retirement obligations), based on year-end costs and assuming continuation of existing economic conditions, further reduced by estimated future income tax expenses, computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the proved oil and gas reserves, less the tax basis of the properties involved and giving effect to the tax deductions and tax credits and allowances relating to the proved oil and gas reserves.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production.

Unconventional. Generally refers to hydrocarbon reservoirs that lack discrete boundaries that typically define conventional reservoirs. Examples include shales, tight sands or coal beds.

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

WTI. West Texas Intermediate, a crude oil pricing index reference.

Working interest. A cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease.

Part I

Item 1 Business

Unless the context requires otherwise, references to the "Company," "Penn Virginia," "we," "us" or "our" in this Annual Report on Form 10-K refer to Penn Virginia Corporation and its subsidiaries.

Description of Business

Penn Virginia Corporation is an independent oil and gas company engaged in the onshore exploration, development and production of crude oil, NGLs and natural gas. Our current operations consist primarily of operating our producing wells in the Eagle Ford Shale field, or Eagle Ford, in South Texas. We also have less significant operations in Oklahoma, primarily in the Granite Wash. We were incorporated in the Commonwealth of Virginia in 1882. Our common stock is publicly traded on the OTC Pink under the symbol "PVAH" subsequent to our delisting from the NYSE on January 12, 2016. Our common stock was previously traded on the NYSE under the symbol "PVA." Our headquarters and corporate office is located in Radnor, Pennsylvania, and our operations are conducted primarily from our office in Houston, Texas. We also have an operations office near our Eagle Ford assets in South Texas.

We operate in and report our financial results and disclosures as one segment, which is exploration, development and production of crude oil, NGLs and natural gas. Each of our operating regions has similar economic characteristics and meets the criteria for aggregation as one reporting segment.

We own a highly contiguous position of approximately 100,000 net acres in the core liquids-rich area or "volatile oil window" of the Eagle Ford, which we believe contains a substantial number of drilling locations and a more than 15-year drilling inventory. In 2015, we spent over $300 million, or substantially all, of our capital expenditures on our Eagle Ford operations and those operations accounted for 7.0 MMBOE, or 88 percent, of our 7.9 MMBOE total production.

We produce predominantly crude oil and NGLs. In 2015, our total production was comprised of 80 percent crude oil and NGLs and 20 percent natural gas. Crude oil and NGLs accounted for 90 percent of our product revenues. We generally sell our crude oil, NGL and natural gas products using short-term floating price physical and spot market contracts.

As of December 31, 2015, our proved reserves were approximately 44 MMBOE, of which 75 percent were proved developed reserves and 84 percent were oil and NGLs. We drilled and completed 61 gross (38.6 net) wells, all in Eagle Ford, in 2015. As of December 31, 2015, we had 432 gross (254.7 net) productive wells, approximately 86 percent of which we operate, and owned approximately 166,000 gross (120,000 net) acres of leasehold and royalty interests, approximately 54 percent of which were undeveloped. For a more detailed discussion of our production, reserves, drilling activities, wells and acreage, see Item 2, "Properties."

Since 2010, we have divested essentially all of our natural gas-focused assets located in East Texas, Mississippi, Appalachia and the Arkoma Basin. In 2014, we sold our natural gas gathering and gas lift infrastructure assets in South Texas as well as the rights to construct an oil gathering system in South Texas. We received aggregate proceeds of approximately $535 million from these transactions. These proceeds were invested primarily in our Eagle Ford operations.

Industry Operating Environment and Outlook

Crude oil prices remained significantly depressed in 2015 and face continued pressure due to domestic and global supply and demand factors. The downward price pressure intensified in late 2015 and early 2016, with crude oil prices dropping below $27 per barrel in February 2016. Natural gas prices faced similar downward pressure in 2015, dropping below $1.70 per MMBtu in December 2015.

In response to these price declines, and given the uncertainty regarding the timing and magnitude of any price recovery, we have suspended our drilling activities. While we intend to resume drilling in 2016, there can be no assurance that we will have adequate capital to do so.

We have also taken other actions set forth below in response to low commodity prices:

- completed an amendment to our Revolver;
- reduced our drilling and completion costs through (i) contract renegotiations, (ii) improved techniques and (iii) capitalizing on lower industry pricing for related products and services;
- sold all of our assets in East Texas for net proceeds of approximately $73 million in August 2015 and sold certain non-core Eagle Ford properties for net proceeds of approximately $13 million in October 2015;
- suspended payment of dividends on our convertible preferred stock;
- reduced our employee headcount by approximately 40 percent from year-end 2014 levels through administrative and operations restructuring initiatives taken in May and October 2015 and February 2016; and
- engaged Kirkland & Ellis LLP, or K&E, and Jefferies LLC, or Jefferies, to advise us with respect to various financing and debt restructuring options.

For additional financial and other information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our Consolidated Financial Statements and Notes thereto included in Item 8, "Financial Statements and Supplementary Data."

Key Contractual Arrangements

In the ordinary course of operating our business, we enter into a number of key contracts for services that are critical with respect to our ability to develop, produce and bring our production to market. The following is a summary of our most significant contractual arrangements.

Oil gathering and transportation service contracts. We have entered into agreements to provide us gathering, intermediate pipeline transportation and supplemental trucking services for a substantial portion of our Eagle Ford crude oil and condensate production. The gathering agreement has a 25-year term and the intermediate transportation agreement has a 10-year term, which is expected to commence in the first half of 2016.

Natural gas service contracts. We have entered into an agreement that provides gas lift, gathering, compression and transportation services for a substantial portion of our natural gas production in the South Texas region until 2039. We have also entered into contracts that provide firm transportation capacity rights for specified volumes of natural gas on various other pipeline systems for terms ranging from one to 15 years. These contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We attempt to sell excess capacity to third parties at our discretion.

Drilling and Completion. Historically, we have had agreements with several vendors to provide oil and gas well drilling and well completion services. Generally, these agreements have been on a month-to-month basis, but from time to time we have entered into agreements for longer terms, some of which may include early termination provisions that require us to pay penalties if we terminate the agreements prior to the end of their original terms. Given the current industry environment and our recent decision to temporarily suspend our drilling operations, we currently have only one drilling contract with respect to which we have given early termination notice. That contract will expire on March 20, 2016, and we could be obligated to pay up to approximately $1.2 million in early termination charges.

Major Customers

We sell a significant portion of our oil and gas production to a relatively small number of customers. For the year ended December 31, 2015, approximately 64 percent of our consolidated product revenues were attributable to three customers: Phillips 66 Company; Sunoco Refining and Marketing, Inc.; and BP Products North America Inc.

Seasonality

Our sales volumes of oil and gas are dependent upon the number of producing wells and, therefore, are not seasonal by nature. We do not believe that the pricing of our oil and NGL production is subject to any meaningful seasonal effects. Historically, the pricing of natural gas is seasonal, typically with higher pricing in the winter months.

Competition

The oil and gas industry is very competitive, and we compete with a substantial number of other companies, many of which are large, well-established and have greater financial and operational resources than we do. Some of our competitors not only engage in the acquisition, exploration, development and production of oil and gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. In addition, the oil and gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers. In the past, competition has been particularly intense in the acquisition of prospective oil and gas properties. Many of our larger competitors may have a competitive advantage when responding to commodity price volatility and overall industry cycles.

Government Regulation and Environmental Matters

Our operations are subject to extensive federal, state and local laws that govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties as well as the issuance of injunctions limiting or prohibiting our activities for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2015, we have recorded asset retirement obligations of $2.6 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general.

In addition, the United States Environmental Protection Agency, or the EPA, has designated energy extraction as one of six national enforcement initiatives, and has indicated that the agency will direct resources towards addressing incidences of noncompliance from natural gas extraction and production activities. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition, results of operations or cash flows. Nevertheless, changes in existing environmental laws or regulations or the adoption of new environmental laws or regulations, including any significant limitation on the use of hydraulic fracturing, could have the potential to adversely affect our financial condition, results of operations and cash flows.

The following is a summary of the significant environmental laws to which our business operations are subject.

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

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and clean up of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA. While there is currently an exclusion from RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or gas, it is possible that some of these wastes could be classified as hazardous waste in the future, and therefore be subject to RCRA.

Oil Pollution Act. The Oil Pollution Act of 1990, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term "waters of the United States" has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA subjects owners of facilities to strict, joint and several liability for all containment and clean up costs, and certain other damages arising from a spill.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, governs the discharge of certain pollutants into waters of the United States. The discharge of pollutants into regulated waters or wetlands without a permit issued by the EPA, the Army Corps of Engineers, or the Corps, or the state is prohibited. The Clean Water Act has been interpreted by these agencies to apply broadly. The EPA and the Corps released a rule to revise the definition of "waters of the United States" ("WOTUS") for all Clean Water Act programs, which went into effect in August 2015. The U.S. Court of Appeals for the Sixth Circuit has stayed the WOTUS rule nationwide pending further action of the court. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." Those regulations will be implemented as they were prior to the effective date of the new WOTUS rule. The WOTUS rule could significantly expand federal control of land and water resources across the U.S., triggering substantial additional permitting and regulatory requirements.

The Clean Water Act also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil. The EPA has proposed new wastewater pretreatment standards that would prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs

Safe Drinking Water Act. The Safe Drinking Water Act, or the SDWA, and the Underground Injection Control Program promulgated under the SDWA, establish the requirements for salt water disposal well activities and prohibit the migration of fluid containing contaminants into underground sources of drinking water. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays like the Eagle Ford and Granite Wash formations. The Fracturing Responsibility and Awareness of Chemicals Act, which has been repeatedly introduced by members of Congress during the past few years, would subject hydraulic fracturing operations to federal regulation under the SDWA and require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing. Such costs and burdens could delay the development of unconventional gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Additionally, the EPA has commenced a comprehensive research study to investigate the potential adverse impacts of hydraulic fracturing on drinking water and ground water. The EPA released a draft report in June 2015, which stated that EPA had not found evidence of widespread, systemic impacts on drinking water resources from hydraulic fracturing operations. This report has not yet been finalized, and the EPA's ultimate conclusions may be impacted by recent comments from the EPA's Science Advisory Board regarding the sufficiency of the data underlying some of the EPA's conclusions.

Chemical Disclosures Related to Hydraulic Fracturing. Certain states in which we operate have adopted regulations requiring the disclosure of chemicals used in the hydraulic fracturing process. For instance, Oklahoma and Texas have implemented chemical disclosure requirements for hydraulic fracturing operations. In May 2014, the EPA issued an advance notice of proposed rulemaking relating to the collection of information on various chemicals and mixtures used in hydraulic fracturing. In July 2015 the EPA's Office of the Inspector General issued a report instructing the EPA to establish and publish an action plan with milestone dates outlining the steps necessary for determining whether to propose a rule by the end of January 2016. The EPA has indicated that it intends to publish a proposed rule in December 2016. We currently disclose all hydraulic fracturing additives we use on www.FracFocus.org, a website created by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

Additionally, in 2015, several environmental groups filed suit in the District of Columbia federal district court against the EPA seeking a response to plaintiffs' October 2012 petition to the EPA to bring the oil and gas industry within the scope of the Toxic Release Inventory, or TRI, reporting requirements under the Emergency Planning and Community Right-to-Know Act, or the EPCRA. The TRI provisions of the EPCRA require covered facilities to report, on an annual basis, releases into the environment of specifically-listed chemicals. As a result, the EPA issued a response letter agreeing to create TRI requirements for natural gas processing plants, but declining to create TRI requirements for the other request areas, which included crude petroleum and natural gas, natural gas liquids, drilling oil and gas wells, oil and gas field exploration services, and oil and gas field services.

Prohibitions and Other Regulatory Limitations on Hydraulic Fracturing. There have been a variety of regulatory initiatives at the state level to restrict oil and gas drilling operations in certain locations. In November 2014, voters in the City of Denton, Texas, approved a local ordinance banning fracking. In May 2015, this local ordinance was preempted by state legislation.

In addition to chemical disclosure rules, some states have implemented permitting, well construction or water withdrawal regulations that may increase the costs of hydraulic fracturing operations. For example, Texas and Pennsylvania have water withdrawal restrictions allowing suspension of withdrawal rights in times of shortages while other states require reporting on the amount of water used and its source.

Increased regulation of and attention given by environmental interest groups, as well as state and federal regulatory authorities, to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or operating wells. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing that are more stringent could cause a decrease in the completion of new oil and gas wells, as well as increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We use hydraulic fracturing extensively and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and gas that we can economically recover.

Clean Air Act. Our operations are subject to the Clean Air Act, or the CAA, and comparable state and local requirements. In 1990, the U.S. Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed, and continue to develop, regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Further, stricter requirements could negatively impact our production and operations. For example, the Texas Commission on Environmental Quality and the Railroad Commission of Texas have been evaluating possible additional regulation of air emissions in response to concerns about allegedly high concentrations of benzene in the air near drilling sites and natural gas processing facilities. These initiatives could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state and federal levels.

In 2012 the EPA issued new rules subjecting certain oil and gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. These rules restrict volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted. These regulations also establish specific requirements regarding emissions from production related wet seal and reciprocating compressors, pneumatic controllers, and storage vessels. In September 2015, the EPA proposed expanding the 2012 NSPS to create additional methane standards for new compressor stations, natural gas processing plants, and well sites. The proposed NSPS would limit natural gas emissions during well completions, impose new leak detection, and ongoing survey, repair, and recordkeeping requirements.

The EPA has also released new draft control guidance for reducing volatile organic compound emissions from existing oil and gas sources in certain ozone non-attainment areas. The EPA acknowledged that some of its recommendations mirror the requirements found in the proposed NSPS for new sources and that, if adopted by states, these recommendations would apply to both new and existing sources of volatile organic compounds in ozone non-attainment areas. If the rules are adopted as proposed and the guidance remains unchanged, they would impose new compliance costs on our operations.

In addition, in November 2015, the EPA also revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. Certain areas of the country previously in compliance with the various National Ambient Air Quality Standards, including areas where we operate, may be reclassified as non-attainment areas. The EPA has not yet designated which areas of the country are out of attainment with the new ground level ozone standard, and it will take the states several years to develop compliance plans for their non-attainment areas. If the areas where we operate are reclassified as non-attainment areas, such reclassifications may make it more difficult to construct new or modified sources of air pollution in those areas. A number of states have also filed or joined suits to challenge the EPA’s new standard in court. While we are not able to determine the extent to which this new standard will impact our business at this time, it does have the potential to have a material impact on our operations and cost structure.

Collectively, these rules and proposed rules, as well as any future laws and their implementing regulations, may require a number of modifications to our operations. We may, for example, be required to install new equipment to control emissions from our well sites or compressors at initial startup or by the applicable compliance deadline. We may also be required to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. We are currently researching the effect these new rules will have on our business, but generally expect them to add to the cost and expense of our operations.

There have been recent claims asserted that individual wells and other facilities should be “aggregated” together and their collective emissions considered in determining whether major source permitting requirements apply under the CAA. Based on several recent court decisions striking down agency determinations and guidance, the EPA may only make these decisions based on physical proximity and is precluded from considering functional relationships between the facilities. In September 2015, the EPA proposed a rule with two options for defining a “source.” The EPA’s “preferred” option would codify the current approach whereby only sources that “are contiguous or are located within a short distance of one another”-a quarter mile-would be considered “adjacent” and thus a “single source.” The EPA’s second proposed option would allow sources located more than a quarter mile away if it they are “functionally interrelated” to the source, for example through a physical connection, such as a pipeline between equipment. If the EPA adopts the “functionally interrelated” test, it would introduce uncertainty into the permitting process and could require more lengthy and costly permitting processes and more expensive emission controls.

Greenhouse Gas Emissions. Both in the United States and worldwide, there is increasing attention being paid to the issue of climate change and the contributing effect of greenhouse gas, or GHG, emissions. On June 28, 2010, the EPA issued the “Final Mandatory Reporting of Greenhouse Gases” Rule, or the Reporting Rule, requiring all stationary sources that emit more than 25,000 tons of GHGs per year to collect and report to the EPA data regarding such emissions. The Reporting Rule establishes a new comprehensive scheme, which began in 2011, requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. On November 9, 2010, the EPA issued final rules applying these regulations to the oil and gas source category, including oil and gas production, natural gas processing, transmission, distribution and storage facilities (Subpart W). In October 2015, the EPA released a final rule adding reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. In January 2016, the EPA proposed additional changes to the reporting requirements under the program. These rules do not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

In addition, in 2009, the EPA issued a final rule known as the EPA's Endangerment Finding, which found that current and projected concentrations of six key GHGs in the atmosphere threaten public health and the environment, as well as the welfare of current and future generations. Legal challenges to these findings have been asserted, and the U.S. Congress is considering legislation to delay or repeal the EPA's actions, but we cannot predict the outcome of this litigation or these efforts. The EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. These rules were subject to judicial challenge, but on June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit rejected challenges to the tailoring rule and other EPA rules relating to the regulation of GHGs under the CAA.

Starting July 1, 2011, the EPA required facilities that must already obtain New Source Review permits for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. On March 27, 2012, the EPA issued its proposed NSPS for carbon dioxide emissions standard from new and modified power plants and held public hearings on the rule in May 2012 and accepted written comments until June 25, 2012. In its June 2013 Climate Action Plan, the Obama Administration announced its intent to issue regulations under Section 111(b) and Section 111(d) of the CAA to set NSPS for both new and existing power plants by June 2015. The Climate Action Plan also directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and natural gas industry.

In August 2015, the EPA issued its final Clean Power Plan rules establishing carbon pollution standards for power plants. The EPA expects each state to develop implementation plans for power plants in its state to meet the individual state targets established in the Clean Power Plan, and has also proposed a federal compliance plan to implement the Clean Power Plan in the event that approvable state plans are not submitted. Judicial challenges have been be filed, which seek a stay of the implementation of the rules. Electricity generated by natural gas often results in lower CO_2 emission rates than other forms of fossil fuels. Depending on the method of implementation selected by the states, and if implementation is not stayed pending resolution of the legal challenges, the Clean Power Plan could increase the demand for natural gas-generated electricity.

The U.S. Supreme Court, in a decision issued on June 23, 2014, addressed whether the EPA's regulation of GHG emissions from new motor vehicles properly triggered GHG permitting requirements for stationary sources under the Clean Air Act. Through its Prevention of Significant Deterioration ("PSD") and Title V Greenhouse Gas Tailoring Rule, the EPA sought to require large industrial facilities, including coal-fired power plants, to obtain permits to emit, and to use best available control technology to curb, GHG emissions. The decision reversed, in part, and affirmed, in part, a 2012 D.C. Circuit decision that upheld the EPA's GHG-related regulations. Specifically, the court held that the EPA exceeded its statutory authority when it interpreted the Clean Air Act to require Prevention of Significant Deterioration and Title V permitting for stationary sources based on their potential GHG emissions. However, the Court also held that the EPA's determination that a source already subject to the PSD program due to its emission of conventional pollutants may be required to limit its GHG emissions by employing the "best available control technology" was permissible.

In addition to regulatory programs aimed at reducing CO_2 emissions, the EPA has also proposed regulating the emission of methane, which is also considered to be a GHG, from the oil and gas sector through the NSPS program. As a result of this continued regulatory focus, future federal GHG regulations of the oil and gas industry remain a possibility. Also, many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities. While it is not possible to predict how any regulations to restrict GHG emissions may come into force, these and other legislative and regulatory proposals for restricting GHG emissions or otherwise addressing climate change could require us to incur additional operating costs or curtail oil and gas operations in certain areas and could also adversely affect demand for the oil and gas we sell.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations, and the provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered species or their habitats. While some of our facilities are in areas that may be designated as a habitat for endangered species, we believe that we are in substantial compliance with the Endangered Species Act. Moreover, the U.S. Fish and Wildlife Service continues its six-year effort to make listing decisions and critical habitat designations where necessary for over 250 species before the end of the agency's 2017 fiscal year, as required under a 2011 settlement approved by the U.S. District Court for the District of Columbia, and many hundreds of additional anticipated listing decisions have already been identified beyond those recognized in the 2011 settlement. The presence of any protected species or the final designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs from species protection measures or could result in limitations, delays, or prohibitions on our exploration and production activities that could have an adverse effect on our ability to develop and produce our reserves.

Employees and Labor Relations

We had a total of 112 employees as of December 31, 2015. We consider our current employee relations to be favorable. We and our employees are not subject to any collective bargaining agreements.

Available Information

Our internet address is http://www.pennvirginia.com. We make available free of charge on or through our website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter and Nominating and Governance Committee Charter, and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 1A Risk Factors

Our business and operations are subject to a number of risks and uncertainties as described below. However, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition, results of operations and cash flows. If any of the following risks actually occur, our business, financial condition, results of operations and cash flows could suffer and the trading price of our common stock could decline.

We have a significant amount of indebtedness, and there is substantial doubt about our ability to continue as a going concern.

As of December 31, 2015, we had an aggregate amount of approximately $1.2 billion of debt outstanding. We will be required to pay interest on our senior notes in the amount of $87.6 million in 2016, including $10.9 million in April 2016 and $32.9 million in May 2016. Our ability to make those payments is severely in doubt. In 2015, we incurred a loss from operations of $1.6 billion, including an impairment charge of $1.4 billion. As of March 11, 2016, we had only $32.3 million in cash and cash equivalents. Pursuant to the Eleventh Amendment to the Revolver dated as of March 15, 2016, or the Eleventh Amendment, the commitments under the Revolver were reduced to $171.8 million, which is equal to our currently outstanding loans ($170 million) and issued letters of credit ($1.8 million) under the Revolver. Because we do not have any unused commitment capacity, we will not be able to draw on the Revolver to pay our second quarter interest payments on our senior notes or for any other purpose. Furthermore, we are required, at the time of borrowing and as a condition to borrowing, to make certain representations to our lenders. We may not currently be able to make these representations, nor is it likely that we will be able to do so in the future unless we can restructure our debt obligations. There can be no assurance that we will be able to restructure our debt obligations. While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or to otherwise extend the maturity dates, and to cure any potential defaults under the agreements governing such debt, there is no assurance that any particular action or actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our debt agreements will be sufficient.

Moreover, our lenders may in the future exercise their right to redetermine our $275 million borrowing base under the Revolver. Pursuant to the Eleventh Amendment, any such redetermination will not occur until after May 15, 2016. If our borrowing base is redetermined below the amount of our outstanding borrowings, a deficiency will result, and any deficiency must be repaid within 60 days. For additional information regarding the Eleventh Amendment, please see Item 9B, "Other Information."

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

The audit report we received with respect to our year-end 2015 consolidated financial statements contains an explanatory paragraph expressing substantial doubt as to our ability to continue as a "going concern." The Revolver requires us to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. As a result, we are in default under the Revolver. Our failure to obtain relief from this requirement under the Revolver could result in an acceleration of all of our outstanding debt obligations.

Under the Revolver, we are required to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. The audit report prepared by our auditors with respect to the financial statements in this Annual Report on Form 10-K includes an explanatory paragraph expressing substantial doubt as to our ability to continue as a "going concern." Therefore, we are in default under the Revolver. Pursuant to the Eleventh Amendment, we have received an agreement from our lenders that such default, together with certain other defaults, will not become events of default under the Revolver until April 12, 2016 (which can be further extended until May 10, 2016 if certain conditions have been satisfied). For additional information regarding the Eleventh Amendment, please see Item 9B, "Other Information." If we do not obtain a waiver or other suitable relief from the lenders under the Revolver prior to the expiration of the extension, there will exist an event of default under the Revolver.

If an event of default occurs under the Revolver, the lenders could accelerate the loans outstanding under the Revolver. In addition, if the lenders under the Revolver accelerate the loans outstanding under the Revolver, there will also be cross-defaults under the indentures related to our 7.25% Senior Notes due 2019, or the 2019 Senior Notes, and our 8.5% Senior Notes due 2020, or the 2020 Senior Notes. If these cross-defaults occurred, the holders of the 2019 Senior Notes or the 2020 Senior Notes could accelerate those notes.

If our lenders or our noteholders accelerate the payment of amounts outstanding under the Revolver, the 2019 Senior Notes or the 2020 Senior Notes, respectively, we do not currently have sufficient liquidity to repay such indebtedness and would need additional sources of capital to do so. We could attempt to obtain additional sources of capital from asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps, or any combination thereof. However, we cannot provide any assurances that we will be successful in obtaining capital from such transactions on acceptable terms, or at all, and if we fail to obtain sufficient additional capital to repay the outstanding indebtedness and provide sufficient liquidity to meet our operating needs, it may be necessary for us to seek protection from creditors under Chapter 11 of the United States Bankruptcy Code, or Chapter 11.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our historical business strategy.

Our business strategy has historically included maintaining a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. In the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our historical business strategy, we may be required to curtail operations, which could adversely affect our financial condition and results of operations.

Unless we can obtain relief from our lenders, we will also be in breach of certain financial covenants under the Revolver during 2016.

Our ability to borrow under the Revolver is subject to compliance with certain financial covenants, including leverage and current ratios. While we were in compliance with the leverage covenant at December 31, 2015, based on our current operating forecast and capital structure, we do not believe that we will be able to comply with the leverage covenant during the next twelve months. Furthermore, we classified all of our debt as current as of December 31, 2015, which resulted in a breach of the current ratio covenant under the Revolver. Pursuant to the Eleventh Amendment, we have received an agreement from our lenders that such default under the Revolver, together with certain other defaults, will not become events of default until April 12, 2016 (which can be further extended until May 10, 2016 if certain conditions have been satisfied). For additional information regarding the Eleventh Amendment, please see Item 9B, "Other Information." If we do not obtain a waiver or other suitable relief from the lenders under the Revolver prior to expiration of the extension, there will exist an event of default under the Revolver. Even if we obtain such a waiver or other relief, we still believe we cannot comply with the leverage covenant during the next twelve months. If we cannot obtain from our lenders a waiver of such potential breach or an amendment of the leverage covenant, our breach would constitute an event of default that could result in an acceleration of substantially all of our outstanding indebtedness. We would not have sufficient capital to satisfy these obligations.

We may seek protection from our creditors under Chapter 11 or an involuntary petition for bankruptcy may be filed against us, either of which could have a material adverse impact on our business, financial condition, results of operations, and cash flows and could place our shareholders at significant risk of losing all of their investment in our shares.

We have engaged financial and legal advisors to assist us in, among other things, analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives to restructure our indebtedness in private transactions. However, if our attempts are unsuccessful or we are unable to complete such a restructuring on satisfactory terms, we may choose to pursue a filing under Chapter 11.

Seeking bankruptcy court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. For as long as a Chapter 11 proceeding continued, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing on our business operations. Bankruptcy court protection also could make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, during the period of time we are involved in a bankruptcy proceeding, our customers and suppliers might lose confidence in our ability to reorganize our business successfully and could seek to establish alternative commercial relationships.

Additionally, all of our indebtedness is senior to the existing common stock in our capital structure. As a result, we believe that seeking bankruptcy court protection under a Chapter 11 proceeding could cause the shares of our existing common stock to be canceled, resulting in a limited recovery, if any, for shareholders of our common stock, and would place shareholders of our common stock at significant risk of losing all of their investment in our shares.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may have a material adverse effect on our business and operations.

Our substantial indebtedness, liquidity issues and efforts to negotiate restructuring transactions may result in uncertainty about our business and cause, among other things:

- third parties to lose confidence in our ability to explore and produce oil and natural gas, resulting in a significant decline in our revenues, profitability and cash flow;
- difficulty retaining, attracting or replacing key employees;
- employees to be distracted from performance of their duties or more easily attracted to other career opportunities;
- our suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

Continued depressed commodity prices have hurt our profitability, financial condition and ability to service our debt as a result of which we have taken several steps to conserve capital which could further adversely affect our business and financial condition.

Our revenues, operating results, cash flows, profitability, growth rate, value of oil and gas properties and ability to service debt depend heavily on prevailing market prices for crude oil, NGLs and natural gas. Average monthly WTI crude oil and natural gas prices have decreased approximately 75 percent and 53 percent from June 2014 to January 2016. These decreases have led us to take steps to conserve capital by, among other things, suspending our drilling operations, completing reductions in force and extending the time for payment of our service providers. While we intend to resume drilling in 2016, there can be no assurance that we will have adequate capital to do so. Likewise, while we intend to pay all amounts due to our service providers, there can be no assurance that we will be able to do so or that our service providers will not decline to work for us or take action against us for non-payment. Furthermore, the lag in operations and reductions in force which we have completed could have an adverse impact on our continuing employees, making it difficult for us to retain their services.

Prices for crude oil, NGLs and natural gas prices are dependent on many factors that are beyond our control.

Prices for crude oil, NGLs and natural gas are dependent on many factors that are beyond our control, including:

- domestic and foreign supplies of crude oil, NGLs and natural gas;
- domestic and foreign consumer demand for crude oil, NGLs and natural gas;
- political and economic conditions in oil or gas producing regions;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree upon and maintain production constraints and oil price controls;
- overall domestic and foreign economic conditions;
- prices and availability of, and demand for, alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and gas;
- the availability, proximity and capacity of gathering, processing, refining and transportation facilities;
- weather conditions; and
- domestic and foreign governmental regulation and taxation.

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

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operating activities. We must make substantial capital expenditures to find, acquire, develop and produce oil and gas reserves. Because of significantly low commodity prices, we may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves with our cash flows from operating activities. Because of our financial and liquidity positions, external sources of capital are limited.

Our common stock has been delisted from the NYSE and will not be listed on any other national securities exchange in the near future.

We received notice from the NYSE that trading of our common stock was suspended at the opening of business on January 12, 2016, and the NYSE filed with the SEC to remove our common stock from listing and registration on the NYSE. As a result, our common stock now trades in the OTC Pink market under the ticker symbol "PVAH." Securities traded in the OTC Pink market generally have significantly less liquidity than securities traded on a national securities exchange, due to factors such as the reduced number of investors that will consider investing in the securities, the reduced number of market makers in the securities, and the reduced number of securities analysts that follow such securities. As a result, holders of shares of our common stock may find it difficult to resell their shares at prices quoted in the market or at all. Because of the limited market and generally low volume of trading in our common stock that could occur, the share price of our common stock could be more likely to be affected by broad market fluctuations, general market conditions, fluctuations in our operating results, changes in the market's perception of our business, and announcements made by us, our competitors or parties with whom we have business relationships. The lack of liquidity in our common stock may also make it difficult for us to issue additional securities for financing or other purposes, or to otherwise arrange for any financing we may need in the future.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or gas reserves will be found. The costs of drilling, completing and operating wells are often substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- elevated pressure or irregularities in geologic formations;
- title problems;
- equipment failures or accidents;
- costs, shortages or delays in the availability of drilling rigs, crews, equipment and materials;
- shortages in experienced labor;
- surface access restrictions;
- failure to or delays in securing necessary regulatory approvals and permits, including delays due to potential hydraulic fracturing regulations;
- fires, explosions, blow-outs and surface cratering; and
- adverse weather conditions.

The prevailing prices of crude oil, NGLs and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services. The availability of drilling rigs and equipment can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. In addition, limitations on the use of hydraulic fracturing could have an adverse effect on our ability to develop and produce oil and gas from new wells, which would reduce our rate of return on these wells and our cash flows. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our business, financial condition, results of operations and cash flows. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

We are exposed to the credit risk of our customers, and nonpayment or nonperformance by these parties would reduce our cash flows.

We are subject to risk from loss resulting from our customers' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of revenues. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly affect our overall credit risk. Recently, many of our customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payments or perform on their obligations to us. In 2015, approximately 64 percent of our total consolidated product revenues resulted from three of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

We participate in oil and gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties own the remaining portion of the working interest under joint venture arrangements. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one party. We could be held liable for joint venture obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the volatility in commodity prices and currently depressed commodity environment increases the likelihood that some of these working interest owners may not be able to fulfill their joint venture obligations. Some of our project partners have experienced liquidity and cash flow problems. These problems have led and may lead our partners to continue to attempt to delay the pace of project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial condition, results of operations and cash flows.

Our business and prospects for future success depend to a significant extent upon the continued service and performance of our management team.

Our business and prospects for future success, including the successful implementation of our strategies and handling of issues integral to our future success, depend to a significant extent upon the continued service and performance of our management team. The loss of any member of our management team, and our inability to attract, motivate and retain substitute management personnel with comparable experience and skills, could materially and adversely affect our business, financial condition, results of operations and cash flows.

Our business depends on gathering, processing, refining and transportation facilities owned by others.

We deliver substantially all of our oil and gas production through pipelines and trucks that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines and trucks, as well as gathering systems, gas processing facilities and downstream refineries. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells, the reduction in wellhead pricing or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and 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, process, refine and market our oil and gas.

We rely on third-party service providers to conduct the drilling and completion operations on properties we operate.

Where we are the operator of a property, we rely on third-party service providers to perform necessary drilling and completion operations. The ability of third-party service providers to perform such drilling and completion operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, natural gas liquids and natural gas, prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations could delay drilling or completion, reduce production from the property or cause other damage to operations, each of which could adversely affect our business, financial condition, results of operations and cash flows.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on the acreage.

Leases on oil and natural gas properties typically have a term after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory through drilling wells to hold the leasehold acreage that we believe is material to our operations, our drilling plans for these areas are subject to change and subject to the availability of capital.

Estimates of oil and gas reserves and future net cash flows are not precise.

This Annual Report on Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to crude oil, NGL and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and, therefore, changes often occur as these variables evolve and commodity prices fluctuate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the estimated quantities and present value of our reserves.

Actual future production, crude oil, NGL and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil, NGL and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2015, approximately 25 percent of our estimated proved reserves were proved undeveloped, compared to 60 percent at December 31, 2014. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

The reserve estimation standards provide that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These standards may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not develop those reserves within the required five-year time frame or cannot demonstrate that we could do so. We experienced negative revisions of 45.6 MMBOE in 2015 due to fewer locations, lower EURs and lower prices compared to year-end 2014.

You should not assume that the present value of estimated future net cash flows (standardized measure) referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. Actual future net cash flows may also be affected by the amount and timing of actual production, availability of financing for capital expenditures necessary to develop our undeveloped reserves, supply and demand for oil and gas, increases or decreases in consumption of oil and gas and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for us.

We may record impairment losses on our oil and gas properties.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower crude oil, NGL and natural gas prices may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all reserves within such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depreciation, depletion and amortization, or DD&A, on the affected properties, which would decrease earnings or result in losses through higher DD&A expense. The revisions may also be significant enough to result in impairment losses on certain properties that would further decrease reported earnings.

GAAP requires that the carrying value of oil and gas properties be reviewed on a periodic basis for possible impairment. An impairment charge is recognized when the carrying value of oil and gas properties is greater than the undiscounted future net cash flows attributable to the property. In addition to revisions to reserves and the impact of lower commodity prices, impairments may occur due to increases in estimated operating and development costs and other factors.

During the past several years, we have been required to impair certain of our oil and gas properties and related assets. We recorded an impairment charge of approximately $1.4 billion during 2015. We could experience additional impairments in the future. While an impairment charge reflects our ability to recover the carrying value of our investments, it does not impact our cash flows from operating activities.

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

In 2015, other companies operated approximately 15 percent of our net production. Our success in properties operated by others will depend upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

Our property acquisitions carry significant risks.

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. In the event we do complete an acquisition, its success will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future crude oil, NGL and natural gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

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

Our initial technical reviews of properties we acquire are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. 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 soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on its results of operations and financial condition.

We are a relatively small company and therefore may not be able to compete effectively.

Compared to many of our competitors in the oil and gas industry, we are a small company. We face difficulties in competing with larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and natural gas plays, to acquire new acreage, and to develop attractive oil and natural gas projects, are significant. We face intense competition in all areas of our business from companies with greater and more productive assets, substantially larger staffs and greater financial and operating resources than we have. Our limited size has placed us at a disadvantage with respect to funding our capital and operating costs, and means that we are more vulnerable to commodity price volatility and overall industry cycles, are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development or production play can have a disproportionately negative impact on us.

We also compete for people, including experienced geologists, geophysicists, engineers and other professionals. Our limited size has placed us at a disadvantage with respect to attracting and retaining management and other professionals with the technical abilities necessary to successfully operate our business.

Our lack of diversification increases the risk of an investment in us and we are vulnerable to risks associated with operating primarily in one major contiguous area.

Our current business is focused primarily in the Eagle Ford in South Texas. Due to the concentrated nature of our business activities, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that are more diversified. In particular, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of crude oil or natural gas produced from wells in the Eagle Ford.

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

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations or financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs and land owners may file claims for alternative water supplies, property damage or bodily injury. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our business, financial condition, results of operations and cash flows. See Item 1, "Business – Government Regulation and Environmental Matters."

Our business involves many operating risks, including hydraulic fracturing, that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for and the production and transportation of oil and gas, including well stimulation and completion activities such as hydraulic fracturing. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures;
- pipeline ruptures or spills;
- uncontrollable flows of oil, natural gas or well fluids;
- migration of fracturing fluids into surrounding groundwater;
- spills or releases of fracturing fluids including from trucks sometimes used to deliver these materials;
- spills or releases of brine or other produced water that may go off-site;
- subsurface conditions that prevent us from (i) stimulating the planned number of stages, (ii) accessing the entirety of the wellbore with our tools during completion or (iii) removing all fracturing-related materials from the wellbore to allow production to begin;
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases; and
- natural disasters and other adverse weather conditions, terrorism, vandalism and physical, electronic and cyber security breaches.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

If we experience any problems with well stimulation and completion activities, such as hydraulic fracturing, our ability to explore for and produce oil or natural gas may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of:

- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, which may include limitations on hydraulic fracturing or the discharge of GHGs;
- the need to shut down, abandon and relocate drilling operations;
- the need to sample, test and monitor drinking water in particular areas and to provide filtration or other drinking water supplies to users of water supplies that may have been impacted or threatened by potential contamination from fracturing fluids;
- the need to modify drill sites to ensure there are no spills or releases off-site and to investigate and/or remediate any spills or releases that might have occurred; or
- suspension of our operations.

In accordance with industry practice, we maintain insurance at a level that balances the cost of insurance with our assessment of the risk and our ability to achieve a reasonable rate of return on our investments. We cannot assure you that our insurance will be adequate to cover losses or liabilities or that we will purchase insurance against all possible losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Access to water to conduct hydraulic fracturing may not be available if water sources become scarce.

The availability of water is crucial to conduct hydraulic fracturing. A significant amount of water is necessary for drilling and completing each well with hydraulic fracturing in Texas. In the past, Texas has experienced severe droughts that have limited the water supplies that are necessary to conduct hydraulic fracturing. Although we have taken measures to secure our water supply, we can make no assurances that sufficient water resources will be available in the short or long term to carry out our current activities.

Our production may not satisfy the minimum gross volume requirements under our gathering agreements with Republic Midstream, LLC, or Republic, and, as a result, we may be required to make deficiency payments.

We have entered into a gathering agreement with Republic that requires us to provide a minimum delivery commitment of 15,000 gross BOPD of crude oil. The commitment is for a 10 year term beginning once the system has been constructed and is operational, currently expected in the first half of 2016. Although our production and reserves are currently sufficient to fulfill the delivery commitment under the agreement, future oil production may not be sufficient to meet the minimum volume requirements. If we do not purchase volumes in the market or make other arrangements to satisfy the commitments, we would be required to make deficiency payments that total $1.75 per undelivered Bbl.

Laws and regulations restricting emissions of greenhouse gases could force us to incur increased capital and operating costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. For example, the EPA implemented rules requiring annual reporting of GHG emissions from specified large GHG emission sources in the United States for emissions occurring after January 1, 2010. In October 2015 the EPA released a final rule adding reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

Moreover, the Obama administration has announced in its Climate Action Plan that it intends to adopt additional regulations to reduce emissions of GHGs in the coming years, likely including further restrictions on emissions of methane from oil and gas operations. More specifically, the EPA issued its final Clean Power Plan rules in August 2015 that establish carbon pollution standards for power plants, and has proposed New Source Performance Standards, or NSPS, to reduce methane emissions from the oil and gas industry. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. See Item 1, "Business – Government Regulation and Environmental Matters."

In addition, 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, floods and other climatic events. If any such events were to occur, they could have an adverse effect on our financial condition, results of operations and cash flows. For a more complete discussion of environmental laws and regulations intended to address climate change and their impact on our business and operations, please see "Business – Environmental Regulation – Climate Change."

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

The practice of hydraulic fracturing has come under increased scrutiny by the environmental community. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into prospective rock formations to stimulate oil and gas production. We use this completion technique on all of our wells. The EPA is studying the potential environmental impacts of hydraulic fracturing and its potential impact on drinking water resources. The EPA released a draft report in June 2015, which stated that EPA had not found evidence of widespread, systemic impacts on drinking water resources from hydraulic fracturing operations. This report has not yet been finalized, and the EPA's ultimate conclusions may be impacted by recent comments from the EPA's Science Advisory Board regarding the sufficiency of the data underlying some of the EPA's conclusions. In May 2014, the EPA issued an advance notice of proposed rulemaking relating to the collection of information on various chemicals and mixtures used in hydraulic fracturing. The EPA has issued final rules under the CAA that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the NSPS and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. The EPA has proposed additional NSPS regulations of volatile organic compound and methane emissions from the oil and gas industry, and has released draft guidance that could potentially extend such requirements to existing oil and gas sources in ozone non-attainment areas.

In light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, certain regulators are also considering additional requirements related to seismic safety for hydraulic fracturing activities. In addition, some states and local governments have enacted legislation or adopted regulations, and the U.S. Congress and other states are considering enacting legislation or adopting regulations, that could impose more stringent permitting, disclosure, monitoring, well construction and water use requirements on hydraulic fracturing operations.

Individually or collectively, such new legislation or regulation could result in increased compliance and operating costs, delays or additional operating restrictions. 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. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. While we do not believe that compliance with such requirements will have a material adverse effect on our operations, these requirements may result in increased operating and compliance costs, increased regulatory burdens and delays in our operations, any of which could be significant.

If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife or their habitat may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Various federal and state statutes prohibit certain actions that harm endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act, CERCLA and the OPA. The U.S. Fish and Wildlife Service 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 oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling, construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, may seek criminal penalties.

Derivative transactions may limit our potential gains and involve other risks.

In order to manage our exposure to price risks in the sale of our crude oil, NGLs and natural gas, we periodically enter into commodity price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of two years or less. While intended to reduce the effects of volatile crude oil, NGL and natural gas prices, such transactions may limit our potential gains if crude oil, NGL or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how crude oil, NGL or natural gas prices fluctuate in the future.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts crude oil, NGL or natural gas prices.

In addition, derivative instruments involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

Our ability to use net operating loss carryforwards to offset future taxable income may be subject to certain limitations.

Our ability to utilize U.S. net operating loss, or NOL, carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended, or the Code. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of our stock by 5% shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50% in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. As of December 31, 2015, we do not believe that an ownership change has occurred; however, to the extent an ownership change has occurred or were to occur in the future, it is possible that the limitations imposed on our ability to use pre-ownership change losses could cause a significant net increase in our U.S. federal income tax liability and could cause U.S. federal income taxes to be paid earlier than they otherwise would be paid if such limitations were not in effect.

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction.

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U. S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income and state income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations. Additionally, legislation could be enacted that increases the taxes states impose on oil and natural gas extraction. Moreover, President Obama has proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an “oil fee” of $10.25 on a per barrel equivalent of crude oil. This fee would be collected on domestically produced and imported petroleum products. The fee would be phased in evenly over five years beginning October 1, 2016. The adoption of this, or similar proposals, would result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be adversely affected.

A cyber incident could result in theft of confidential information, data corruption or operational disruption.

The oil and gas industry is dependent on digital technologies to conduct certain exploration, development and production activities. Software programs are used for, among other things, reserve estimates, seismic interpretation, modeling and compliance reporting. In addition, the use of mobile communication is widespread. Increasingly, we must protect our business against potential cyber incidents including attacks.

If our systems for protecting against cyber incidents prove not to be sufficient, we could be adversely affected by unauthorized access to our digital systems which could result in theft of confidential information, data corruption or operational disruption. As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and enhance our protective systems or to investigate and remediate any vulnerabilities.

Item 1B Unresolved Staff Comments

We have received no written SEC staff comments regarding our periodic or current reports under the Exchange Act that were issued 180 days or more preceding the end of our 2015 fiscal year and remain unresolved.

Item 2 Properties

As of December 31, 2015, our primary oil and gas assets are located in Gonzales and Lavaca Counties in South Texas and Washita and Custer Counties in Western Oklahoma.

Facilities

All of our office facilities are leased and we believe that our facilities are adequate for our current needs.

Title to Oil and Gas Properties

Prior to completing an acquisition of producing oil and gas assets, we review title opinions on all material leases. As is customary in the oil and gas industry, however, we make a cursory review of title when we acquire farmout acreage or undeveloped oil and gas leases. Prior to the commencement of drilling operations, a thorough title examination is conducted. To the extent the title examination reflects defects, we cure such title defects. If we are unable to cure any title defect of a nature such that it would not be prudent to commence drilling operations on a property, we could suffer a loss of our investment in the property. Our oil and gas properties are subject to customary royalty interests, liens for debt obligations, current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties. We believe that we have satisfactory title to all of our properties and the associated oil and gas in accordance with standards generally accepted in the oil and gas industry.

Summary of Oil and Gas Reserves

Proved Reserves

The following tables summarize certain information regarding our estimated proved reserves as of December 31 for each of the years presented:

	Crude Oil	NGLs	Natural Gas	Oil Equivalents	Standardized Measure	PV10
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	$ in millions	$ in millions
2015						
Developed						
Producing	19.6	6.1	36.8	31.8	$ 325.6	$ 325.6
Non-producing	0.6	0.1	0.4	0.8	4.3	4.3
	20.2	6.2	37.2	32.6	329.9	329.9
Undeveloped	9.3	1.0	5.0	11.1	(6.6)	(6.6)
	29.5	7.2	42.2	43.7	$ 323.3	$ 323.3
Price measurement used [1]	$45.78/Bbl	$13.15/Bbl	$2.70/MMBtu			
2014						
Developed						
Producing	21.8	7.4	77.9	42.1	$ 794.9	$ 989.9
Non-producing	0.3	0.7	16.6	3.8	8.6	10.7
	22.1	8.1	94.5	45.9	803.5	1,000.6
Undeveloped	47.0	11.1	64.7	68.9	378.9	471.9
	69.0	19.2	159.2	114.8	$ 1,182.4	$ 1,472.5
Price measurement used [1]	$92.91/Bbl	$25.49/Bbl	$4.32/MMBtu			
2013						
Developed						
Producing	19.0	7.5	146.5	50.9	$ 701.7	$ 953.1
Non-producing	0.3	1.0	16.7	4.1	7.3	9.9
	19.3	8.5	163.2	55.0	709.0	963.0
Undeveloped	41.4	13.4	158.9	81.3	554.8	753.6
	60.7	21.9	322.1	136.3	$ 1,263.8	$ 1,716.6
Price measurement used [1]	$103.11/Bbl	$31.10/Bbl	$3.47/MMBtu			

[1] Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu. The representative prices of crude oil and natural gas were adjusted for basis differentials to arrive at the appropriate net price. NGL prices were estimated as a percentage of the base crude oil price.

All of our reserves are located in the continental United States. The following table sets forth by region the estimated quantities of proved reserves and the percentages thereof that are represented by proved developed reserves as of December 31, 2015:

Region	Proved Reserves	% of Total Proved Reserves	% Proved Developed
	(MMBOE)		
South Texas	40.1	92%	72%
Mid-Continent and other [1]	3.6	8%	100%
	43.7	100%	75%

[1] Includes approximately 0.1 MMBOE attributable to our three active Marcellus Shale wells.

Proved Undeveloped Reserves

The proved undeveloped reserves included in our reserve estimates relate to wells that are forecasted to be drilled within the next three years, assuming availability of capital. The following tables set forth the changes in our proved undeveloped reserves during the year ended December 31, 2015 and the total proved undeveloped reserves as of December 31, 2015 by region:

	Crude Oil	NGLs	Natural Gas	Oil Equivalents
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)
Proved undeveloped reserves at beginning of year	47.0	11.1	64.7	68.9
Revisions of previous estimates	(30.8)	(7.9)	(41.4)	(45.6)
Extensions, discoveries and other additions	1.2	0.1	0.6	1.4
Sale of reserves in place	(1.5)	(0.4)	(9.5)	(3.5)
Conversion to proved developed reserves	(6.6)	(1.9)	(9.4)	(10.1)
Proved undeveloped reserves at end of year	9.3	1.0	5.0	11.1
South Texas	9.3	1.0	5.0	11.1
Mid-Continent and other	—	—	—	—
	9.3	1.0	5.0	11.1

In 2015, our proved undeveloped reserves decreased by 57.8 MMBOE. We experienced negative revisions of 45.6 MMBOE due to fewer locations, lower EURs and lower prices compared to year-end 2014. Extensions, discoveries and other additions of 1.4 MMBOE were attributable to our development activities in Eagle Ford. We sold our Haynesville Shale and Cotton Valley assets in East Texas as well as certain non-core Eagle Ford properties resulting in decreases of 2.0 MMBOE and 1.5 MMBOE. In addition, we converted 10.1 MMBOE from proved undeveloped to proved developed reserves in Eagle Ford. During 2015, we incurred capital expenditures of approximately $222.6 million in connection with the conversion of proved undeveloped reserves to proved developed reserves.

Preparation of Reserves Estimates and Internal Controls

The proved reserve estimates were prepared by DeGolyer and MacNaughton, Inc., our independent third party petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see the Supplemental Information on Oil and Gas Producing Activities (Unaudited) in our Notes to the Consolidated Financial Statements and the report of DeGolyer and MacNaughton, Inc., dated February 3, 2016, which is included as an Exhibit to this Annual Report on Form 10-K. We did not file any reports during the year ended December 31, 2015 with any federal authority or agency with respect to our estimate of oil and gas reserves.

Our policies and practices regarding the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC’s regulations and GAAP. Our Vice President, Operations & Engineering is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc. Our Vice President, Operations & Engineering has over 30 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the State of Texas as a Professional Engineer. Our internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For additional information about the risks inherent in our estimates of proved reserves, see Item 1A, “Risk Factors.”

Qualifications of Third Party Petroleum Engineers

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

Oil and Gas Production, Production Prices and Production Costs

In the tables that follow, we have presented our former operations in the Haynesville Shale and Cotton Valley in East Texas and Selma Chalk in Mississippi, which were sold in 2015 and 2014 as "Divested properties." The sales of those operations represented complete divestitures and we have retained no interests therein. Our remaining operations are represented in the Eagle Ford in South Texas, the Granite Wash in Oklahoma and relatively minor operations in the Marcellus Shale in Pennsylvania.

Oil and Gas Production by Region

The following tables set forth by region our total production and average daily production for the periods presented:

	Total Production for the Year Ended December 31,		
Region	**2015**	**2014**	**2013**
	(MBOE)		
South Texas [1]	6,995	5,913	4,091
Mid-Continent and other [2]	479	765	962
Divested properties [3]	449	1,256	1,771
	7,923	7,934	6,824

	Average Daily Production for the Year Ended December 31,		
Region	**2015**	**2014**	**2013**
	(BOEPD)		
South Texas [1]	19,165	16,201	11,208
Mid-Continent and other [2]	1,311	2,096	2,636
Divested properties [3]	1,847	3,441	4,852
	22,323	21,738	18,696

[1] Includes total production and average daily production of approximately 92 MBOE (303 BOEPD), 96 MBOE (264 BOEPD) and 33 MBOE (90 BOEPD) for 2015, 2014 and 2013, respectively, attributable to certain non-core Eagle Ford properties that we sold in October 2015.

[2] Includes total production and average daily production of approximately 19 MBOE (61 BOEPD), 22 MBOE (61 BOEPD) and 29 MBOE (81 BOEPD) for 2015, 2014 and 2013, respectively, attributable to certain Mid-Continent properties that we sold in October 2015. Also includes total production and average daily production of approximately 22 MBOE (60 BOEPD), 24 MBOE (66 BOEPD) and 25 MBOE (67 BOEPD) for 2015, 2014 and 2013, respectively, attributable to our three active Marcellus Shale wells.

[3] We sold all of our properties in the Haynesville Shale and Cotton Valley in East Texas in August 2015, which represented total production and average daily production of approximately 449 MBOE (1,847 BOEPD), 844 MBOE (2,311 BOEPD) and 1,020 MBOE (2,794 BOEPD) in 2015, 2014 and 2013, respectively. We sold all of our properties in the Selma Chalk in Mississippi in July 2014, which represented annual production and average daily production of approximately 412 MBOE (1,946 BOEPD) and 751 MBOE (2,058 BOEPD) in 2014 and 2013.

Production Prices and Production Costs

The following table sets forth the average sales prices per unit of volume and our average production costs, not including ad valorem and production/severance taxes, per unit of production for the periods presented:

	Year Ended December 31,		
	2015	**2014**	**2013**
Average prices:			
Crude oil ($ per Bbl)	$ 44.81	$ 91.50	$ 101.13
NGLs ($ per Bbl)	$ 12.24	$ 31.14	$ 31.30
Natural gas ($ per Mcf)	$ 2.62	$ 4.44	$ 3.64
Aggregate ($ per BOE)	$ 33.19	$ 64.64	$ 63.11
Average production and lifting cost ($ per BOE):			
Lease operating	$ 5.36	$ 6.09	$ 5.20
Gathering processing and transportation	3.01	2.31	1.88
	$ 8.37	$ 8.40	$ 7.08

Significant Fields

Our properties in the Eagle Ford in South Texas, which contain primarily oil reserves, represented approximately 92 percent of our total equivalent proved reserve quantities as of December 31, 2015.

The following table sets forth certain information with respect to this field for the periods presented:

	Year Ended December 31,		
	2015	**2014**	**2013**
Production:			
Crude oil (MBbl)	4,817	4,450	3,197
NGLs (MBbl)	1,170	773	478
Natural gas (MMcf)	6,026	4,070	2,406
Total (MBOE)	6,991	5,901	4,077
Percent of total company production	88%	74%	60%
Average prices:			
Crude oil ($ per Bbl)	$ 44.79	$ 90.57	$ 101.55
NGLs ($ per Bbl)	$ 11.04	$ 25.23	$ 26.68
Natural gas ($ per Mcf)	$ 2.64	$ 4.20	$ 3.52
Aggregate ($ per BOE)	$ 34.98	$ 74.49	$ 84.85
Average production and lifting cost ($ per BOE) [1]:			
Lease operating	$ 5.04	$ 5.36	$ 4.30
Gathering processing and transportation	2.66	1.76	1.08
	$ 7.70	$ 7.12	$ 5.38

[1] Excludes production/severance and ad valorem taxes.

Drilling and Other Exploratory and Development Activities

The following table sets forth the gross and net development wells that we drilled during the years ended December 31, 2015, 2014 and 2013, respectively, and wells that were in progress at the end of each year. There were no exploratory wells drilled in any of the years presented. The number of wells drilled refers to the number of wells completed at any time during the year, regardless of when drilling was initiated.

	2015		2014		2013	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development						
Productive	61	38.6	83	50.8	58	34.1
Dry well	—	—	1	0.8	—	—
Under evaluation	—	—	—	—	1	0.5
Total	61	38.6	84	51.6	59	34.6
Wells in progress at end of year [1]	4	2.3	28	14.3	16	11.5

[1] Includes two gross (1.7 net) wells completing, one gross (0.3 net) well waiting on completion and one gross (0.3 net) well being drilled as of December 31, 2015.

The following table sets forth the regions in which we drilled our wells for the periods presented:

	2015		2014		2013	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South Texas	61	38.6	84	51.6	57	34.1
Mid-Continent and other	—	—	—	—	2	0.5
	61	38.6	84	51.6	59	34.6

Present Activities

As of December 31, 2015, we had four gross (2.3 net) wells in progress, all of which were located in the Eagle Ford in South Texas. As of March 4, 2016, all four of these wells had been successfully completed and were producing.

Delivery Commitments

We generally sell our oil, NGL and natural gas products using short-term floating price physical and spot market contracts. We have commitments to provide minimum deliveries of crude oil of 15,000 BOPD in our South Texas region for a period of ten years under a gathering agreement with Republic Midstream, LLC, or Republic. This commitment is for a 10 year term beginning once the system has been constructed and is operational, currently expected in the first half of 2016. Although, our production and reserves are currently sufficient to fulfill the delivery commitment under the agreement, future oil production may not be sufficient to meet the minimum volume requirements. If we do not purchase volumes in the market or make other arrangements to satisfy the commitments, we would be required to make deficiency payments that total $1.75 per undelivered Bbl.

We also have a contractual obligation for certain firm transportation capacity in the Appalachian region that expires in 2022 and, as a result of the sale of our natural gas assets in West Virginia, Kentucky and Virginia in 2012, we no longer have production to satisfy this commitment. While we sell our unused firm transportation to the extent possible, we recognized an obligation in 2012 representing the liability for estimated discounted future net cash outflows over the remaining term of the contract. The undiscounted amount payable on an annual basis for the each of the next five years is $2.7 million and a combined amount of $4.6 million is expected to be payable for 2021 through expiration in 2022.

Productive Wells

The following table sets forth by region the productive wells in which we had a working interest as of December 31, 2015:

	Primarily Oil		Primarily Natural Gas		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South Texas [1]	332	209.7	—	—	332	209.7
Mid-Continent and other	2	1.5	98	43.5	100	45.0
	334	211.2	98	43.5	432	254.7

[1] Includes wells in the Austin Chalk.

Of the total wells presented in the table above, we are the operator of 333 gross (299 oil and 34 gas) and 220 net (198.3 oil and 21.7 gas) wells. In addition to the above working interest wells, we own royalty interests in 9 gross wells.

Acreage

The following table sets forth by region our developed and undeveloped acreage as of December 31, 2015 (in thousands):

	Developed		Undeveloped		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South Texas	75.6	48.3	61.4	51.7	137.0	100.0
Mid-Continent and other	16.9	8.4	12.0	11.9	28.9	20.3
	92.5	56.7	73.4	63.6	165.9	120.3

The primary terms of our leases generally range from three to five years and we do not have any concessions. As of December 31, 2015, our net undeveloped acreage is scheduled to expire as shown in the table below, unless the primary lease terms are, where appropriate, extended, HBP or otherwise changed:

	2016	2017	2018	Thereafter
Percent of gross undeveloped acreage	43%	35%	8%	14%
Percent of net undeveloped acreage	45%	31%	6%	18%

We do not believe that the scheduled expiration of our undeveloped acreage will substantially affect our ability or plans to conduct our exploration and development activities.

Item 3 Legal Proceedings

See Note 14 to our Consolidated Financial Statements included in Item 8, "Financial Statements and Supplementary Data," for a more detailed discussion of our legal contingencies. We are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Item 4 Mine Safety Disclosures

Not applicable.

Part II

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

Market Information

On January 13, 2016, our common stock began trading on the OTC Pink under the symbol "PVAH." Prior to being suspended from trading on January 12, 2016, our common stock was traded on the NYSE under the symbol "PVA."

The high and low sales prices (composite transactions) related to each fiscal quarter in 2015 and 2014, as reported by the NYSE, were as follows:

	Sales Price	
Quarter Ended	High	Low
December 31, 2015	$ 1.23	$ 0.26
September 30, 2015	$ 4.39	$ 0.53
June 30, 2015	$ 8.03	$ 3.87
March 31, 2015	$ 7.91	$ 4.55
December 31, 2014	$ 12.89	$ 4.32
September 30, 2014	$ 17.20	$ 11.53
June 30, 2014	$ 18.20	$ 13.54
March 31, 2014	$ 18.04	$ 8.91

Equity Holders

As of February 26, 2016, there were 366 record holders and 16,483 beneficial owners (held in street name) of our common stock.

Dividends

We have not in the last three fiscal years, nor do we intend in the foreseeable future, to pay any cash dividends on our common stock. Additionally, pursuant to the Eleventh Amendment, we are no longer permitted to make payments of dividends on our common stock.

Securities Authorized for Issuance Under Equity Compensation Plans

See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" and Note 16 to our Consolidated Financial Statements included in Item 8, "Financial Statements and Supplementary Data" for information regarding shares of common stock authorized for issuance under our stock compensation plans.

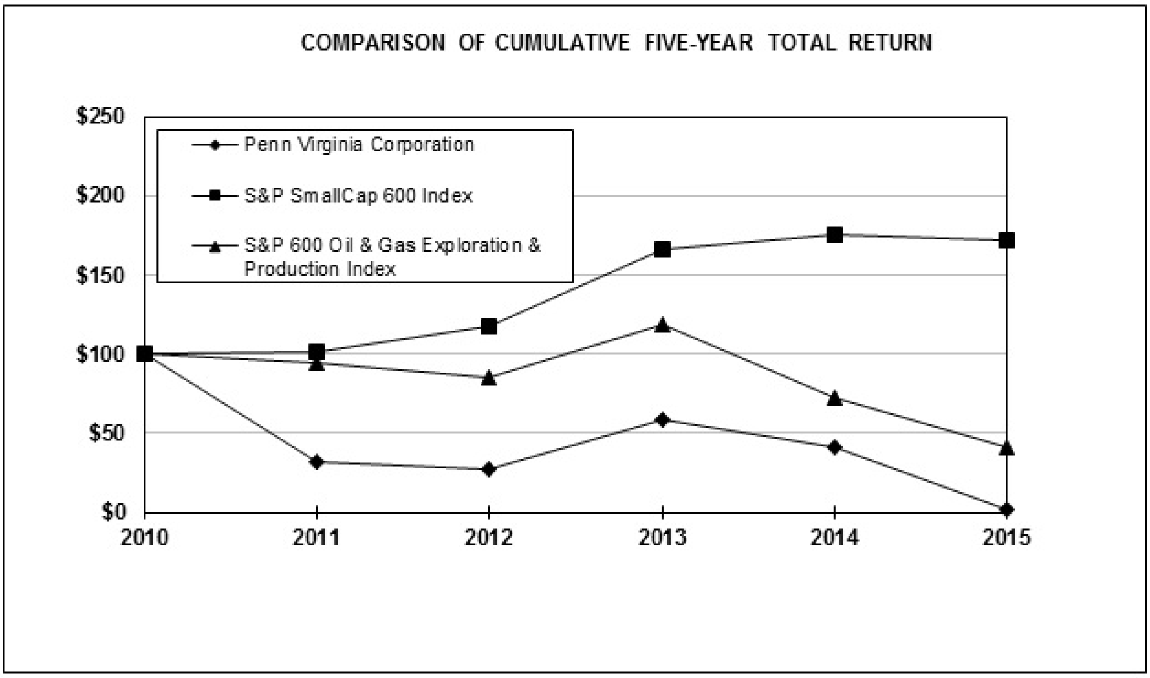
Issuer Purchases of Equity Securities

We did not repurchase any shares of our common stock in the fourth quarter of 2015.

A portion of the compensation for certain non-employee members of our board of directors has been paid in deferred common stock units in recent years through the third quarter of 2015. Each deferred common stock unit represents one share of common stock, vests immediately upon issuance, and is available to the holder upon retirement from our board of directors. Deferred common stock units that have not been converted into common stock are presented for financial reporting purposes as treasury stock carried at cost.

Performance Graph

The following graph compares our five-year cumulative total shareholder return (assuming reinvestment of dividends) with the cumulative total return of the Standard & Poor's 600 Oil & Gas Exploration & Production Index and the Standard & Poor's Small Cap 600 Index. As of December 31, 2015, there were nine exploration and production companies in the Standard & Poor's 600 Oil & Gas Exploration & Production Index: Bill Barret Corporation, Bonanza Creek Energy Inc, Carrizo Oil & Gas, Inc., Contango Oil & Gas Company, Northern Oil & Gas, Inc., PDC Energy, Inc., Rex Energy Corporation, Stone Energy Corporation and Synergy Resources Corporation. The graph assumes $100 is invested on January 1, 2011 in us and each index at December 31, 2010 closing prices.



	December 31,									
	2011		2012		2013		2014		2015	
Penn Virginia Corporation	$	32.23	$	27.45	$	58.70	$	41.58	$	1.87
S&P Small Cap 600 Index	$	101.02	$	117.51	$	166.05	$	175.61	$	172.15
S&P 600 Oil & Gas Exploration & Production Index	$	94.15	$	85.10	$	119.34	$	73.06	$	41.52

Item 6 Selected Financial Data

The following selected historical financial and operating information was derived from our Consolidated Financial Statements as of and for each of the five years ended December 31, 2015. The selected financial data should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our Consolidated Financial Statements and the accompanying Notes and Supplementary Data in Item 8, "Financial Statements and Supplementary Data."

	2015	2014	2013	2012	2011
	(in thousands, except per share amounts)				
Statements of Operations Data:					
Revenues	$ 305,298	$ 636,773	$ 431,468	$ 317,149	$ 306,005
Operating loss [1]	$ (1,565,041)	$ (615,985)	$ (92,046)	$ (147,091)	$ (155,419)
Net income (loss)	$ (1,582,961)	$ (409,592)	$ (143,070)	$ (104,589)	$ (132,915)
Preferred stock dividends [2]	$ 22,789	$ 17,148	$ 6,900	$ 1,687	$ —
Loss attributable to common shareholders	$ (1,605,750)	$ (430,996)	$ (149,970)	$ (106,276)	$ (132,915)
Common Stock Data:					
Loss per common share, basic	$ (21.81)	$ (6.26)	$ (2.41)	$ (2.22)	$ (2.90)
Loss per common share, diluted	$ (21.81)	$ (6.26)	$ (2.41)	$ (2.22)	$ (2.90)
Weighted-average shares outstanding:					
Basic	73,639	68,887	62,335	47,919	45,784
Diluted	73,639	68,887	62,335	47,919	45,784
Actual shares outstanding at year-end	81,253	71,569	65,307	55,117	45,714
Dividends declared per share of common stock	$ —	$ —	$ —	$ 0.113	$ 0.225
Market value at year-end	$ 0.30	$ 6.68	$ 9.43	$ 4.41	$ 5.29
Number of shareholders	16,849	18,306	11,335	7,656	6,787
Preferred Stock Data [3]:					
Actual shares outstanding at year-end:					
Series A	3,915	7,945	11,500	11,500	—
Series B	27,551	32,500	—	—	—
Dividends declared per share of preferred stock [4]:					
Series A	$ 300.00	$ 600.00	$ 600.00	$ 146.67	$ —
Series B	$ 300.00	$ 348.33	$ —	$ —	$ —
Balance Sheet and Other Financial Data:					
Property and equipment, net	$ 344,395	$ 1,825,098	$ 2,237,304	$ 1,723,359	$ 1,777,575
Total assets [5]	$ 517,725	$ 2,201,810	$ 2,472,830	$ 1,831,733	$ 1,929,819
Total debt [5]	$ 1,224,383	$ 1,085,429	$ 1,252,808	$ 583,503	$ 684,073
Shareholders' equity (deficit)	$ (915,121)	$ 675,817	$ 788,804	$ 895,116	$ 846,309
Cash provided by operating activities	$ 169,303	$ 282,724	$ 261,512	$ 241,458	$ 144,741
Cash paid for capital expenditures	$ 364,844	$ 774,139	$ 504,203	$ 370,907	$ 445,623
Other Statistical Data:					
Total production (MBOE)	7,923	7,934	6,824	6,513	7,759
Proved reserves (MMBOE)	44	115	136	113	147

[1] Operating loss for 2015, 2014, 2013, 2012 and 2011 included impairment charges of $1.4 billion, $791.8 million, $132.2 million, $104.5 million and $104.7 million, respectively.

[2] Includes accumulated preferred stock dividends of $10.7 million for 2015 as described in footnote 4 below. Excludes inducements paid for the conversion of preferred stock of $4.3 million in 2014.

[3] Outstanding preferred stock is in the form of depositary shares representing a 1/100th ownership interest in a share of either our 6% Series A Convertible Perpetual Preferred Stock, or Series A Preferred Stock, or our 6% Series B Convertible Perpetual Preferred Stock, or Series B Preferred Stock, as applicable. Each share of the Series A Preferred Stock and B Preferred Stock has a liquidation preference of $10,000 per share or $100 per depositary share.

[4] In September 2015, we suspended our quarterly dividends on the Series A Preferred Stock and the Series B Preferred Stock. The suspension resulted in the accumulation of dividends for the quarterly periods ended September 30, 2015 and December 31, 2015 of $1.7 million for the Series A Preferred Stock and $9.0 million for the Series B Preferred Stock.

[5] Total assets and total debt have been adjusted downward from the prior year presentation by $24.6 million, $28.2 million, $11.3 million and $13.2 million as of December 31, 2014, 2013, 2012 and 2011, respectively, due the adoption in 2015 of ASU No. 2015–03, *Simplifying the Presentation of Debt Issuance Costs* , or ASU 2015–03 on a retrospective basis. ASU 2015–03 requires that debt issuance costs, which were previously presented as assets, be presented as a direct reduction to the face amount of the underlying debt instruments to which they are attributable. In addition, total assets were further reduced by $0.1 million and $6.1 million as of December 31. 2014 and 2013 due to the adoption in 2015 of ASU 2015–17, *Balance Sheet Classification of Deferred Taxes* , which requires the combination of all deferred income tax assets and liabilities to be presented as a single noncurrent amount.

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 Notes thereto included in Item 8, “Financial Statements and Supplementary Data.” All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Also, due to the combination of different units of volumetric measure and the number of decimal places presented, certain results may not calculate explicitly from the values presented in the tables.

Overview and Executive Summary

We are an independent oil and gas company engaged in the exploration, development and production of oil, NGLs and natural gas. Our current operations consist primarily of operating our producing wells in the Eagle Ford in South Texas. We also have less significant operations in Oklahoma, primarily in the Granite Wash.

The majority of our Eagle Ford wells were drilled by us between 2011 and 2015. As commodity prices began their precipitous decline in the second half of 2014, we reduced our capital program while exploiting our most productive drilling locations, attempting to maintain a consistent level of period-to-period growth to offset natural production declines and securing our most strategic acreage through the drillbit.

We began 2015 with eight drilling rigs operating in the Eagle Ford. All of these rigs were initially contracted in 2014 or earlier at times when (i) the spot price for crude oil was substantially higher and (ii) we were executing our business plans to aggressively develop our acquired acreage in this region. By the end of 2015, we had reduced our capital program to one operated drilling rig.

Throughout 2015, we explored strategic alternatives to enhance liquidity, including first and second lien financing transactions. In December 2015, a potential first lien financing agreement was terminated. We incurred $6.2 million in professional fees and consulting costs associated with this proposed transaction and other financing efforts during 2015.

The continued deterioration of commodity prices as reflected in the future strip pricing as of December 31, 2015 triggered an impairment of approximately $1.4 billion to our Eagle Ford properties, reducing their carrying value to their estimated fair value.

The following table sets forth certain historical summary operating and financial statistics for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Total production (MBOE)	7,923	7,934	6,824
Average daily production (BOEPD)	22,323	21,738	18,696
Crude oil and NGL production (MBbl)	6,304	5,754	4,417
Crude oil and NGL production as a percent of total	80%	73%	65%
Product revenues, as reported	$ 262,980	$ 512,882	$ 430,693
Product revenues, adjusted for derivatives	$ 401,149	$ 505,458	$ 429,651
Crude oil and NGL revenues as a percent of total, as reported	90%	89%	88%
Realized prices:			
Crude oil ($/Bbl)	$ 44.81	$ 90.50	$ 101.13
NGL ($/Bbl)	$ 12.24	$ 31.14	$ 31.30
Natural gas ($/Mcf)	$ 2.62	$ 4.44	$ 3.64
Aggregate ($/BOE)	$ 33.19	$ 64.64	$ 63.11
Production and lifting costs ($/BOE):			
Lease operating	$ 5.36	$ 6.09	$ 5.20
Gathering, processing and transportation	$ 3.01	$ 2.31	$ 1.88
Production and ad valorem taxes ($/BOE)	$ 2.06	$ 3.53	$ 3.28
General and administrative ($/BOE) [1]	$ 4.99	$ 5.15	$ 6.46
Total operating costs ($/BOE)	$ 15.42	$ 17.08	$ 16.82
Depreciation, depletion and amortization ($/BOE)	$ 42.22	$ 37.85	$ 35.99
Cash provided by operating activities	$ 169,303	$ 282,724	$ 261,512
Cash paid for capital expenditures	$ 364,844	$ 774,139	$ 504,203
Cash and cash equivalents at end of period	$ 11,955	$ 6,252	$ 23,474
Debt outstanding, net of discount, at end of period	$ 1,245,000	$ 1,110,000	$ 1,281,000
Credit available under revolving credit facility at end of period [2]	$ —	$ 413,196	$ 191,346
Proved reserves (MMBOE)	44	115	136
Net development wells drilled and completed	38.6	51.6	34.6

[1] Excludes equity-classified share-based compensation, which is a non-cash expense, of $0.57, $0.46 and $0.84 and liability-classified share-based compensation of $(0.09), $0.57 and $0.60 for the years ended December 31, 2015, 2014 and 2013, respectively.

[2] As of December 31, 2015, we were and continue to be unable to draw on the Revolver (see "Key Developments" and "Financial Condition" sections that follow).

Key Developments

The following general business developments and corporate actions in 2015 and 2016 had or may have a significant impact on our results of operations, financial position and cash flows:

Depressed Commodity Prices and Our Hedging Program

Commodity prices have exhibited significant volatility and continued a decline that began in mid-2014 and has lasted throughout 2015 and into 2016. Crude oil prices declined from a high of over $105 per barrel in June 2014 to less than $27 per barrel in February 2016. Natural gas prices faced similar downward pressure in 2015, dropping below $1.70 per MMBtu in December 2015. The deterioration of commodity prices triggered an impairment of approximately $1.4 billion to our Eagle Ford properties. Our crude oil derivatives provided cash settlements of $137.5 million during the year ended December 31, 2015. For 2016, we have hedged a total of approximately 6,000 BOPD at a weighted-average swap price of $80.41 per barrel. We expect to remain unhedged with respect to natural gas production for the foreseeable future.

Ongoing Efforts to Refinance the Company and Improve Liquidity

As of December 31, 2015, the total outstanding principal amount of our debt obligations was $1.2 billion. We are continuing to actively explore and evaluate various strategic alternatives to reduce the level of our long-term debt and lower our future cash interest obligations. In January 2016, we retained K&E and Jefferies to provide strategic advice generally and to act as our advisors in that regard. The timing and outcome of these efforts is highly uncertain. One or more of these alternatives could potentially be consummated without the consent of any one or more of our current security holders and, if consummated, could be dilutive to the holders of our outstanding equity securities and adversely affect the trading prices and values of our current debt and equity securities or if we were to seek protection under the bankruptcy laws, could cause the shares of our common stock to be canceled, with limited recovery, if any. Furthermore, there can be no assurance that any of these alternatives will be successful on acceptable terms or at all.

While we were in compliance with the leverage covenant under the Revolver at December 31, 2015, based on our current operating forecast and capital structure, we do not believe that we will be able to comply with the leverage covenant during the next twelve months. Furthermore, we reclassified all of our debt as current as of December 31, 2015, which represents a breach of the current ratio covenant under the Revolver. Pursuant to the Eleventh Amendment to the Revolver, we have received an agreement from our lenders that such default, together with certain other defaults, will not become events of default under the Revolver until April 12, 2016 (which can be further extended until May 10, 2016 if certain conditions have been satisfied). If we do not obtain a waiver or other suitable relief from the lenders under the Revolver before the extension expires, there will exist an event of default under the Revolver. Even if we obtain such a waiver or other relief, we still believe we cannot comply with the leverage covenant during the next twelve months. If we cannot obtain from our lenders a waiver of such potential breach or an amendment of the leverage covenant, our breach would constitute an event of default that could result in an acceleration of substantially all of our outstanding indebtedness. We would not have sufficient capital to satisfy these obligations. For additional information regarding the Eleventh Amendment, please see Item 9B, “Other Information.”

Additionally, as further described under “Financial Condition – Ability to Continue as a Going Concern” below, our registered independent public accountants have issued an opinion with a going concern explanatory paragraph on our consolidated financial statements. As a result, we are in default under our Revolver. Pursuant to the Eleventh Amendment, we have received an agreement from our lenders that such default, together with certain other defaults, will not become events of default under the Revolver until April 12, 2016 (which can be further extended until May 10, 2016 if certain conditions have been satisfied). If we are unable to obtain a waiver or other suitable relief with respect to these defaults, an event of default may occur and could result in an acceleration of our Revolver and potential cross-default and acceleration of substantially all of our other indebtedness. We would not have sufficient capital to satisfy these obligations

Reduced Capital Budget and Suspension of Drilling Program

In response to the recent declines in commodity prices, and given the uncertainty regarding the timing and magnitude of any price recovery, we suspended our drilling activities in February 2016. While we intend to resume drilling in 2016, there can be no assurance that we will have adequate capital to do so.

Revolver Amendments and Commitment and Borrowing Base Reduction

On March 15, 2016, we entered into the Eleventh Amendment to the Revolver. The Eleventh Amendment provides (i) for an extension before certain events of default under the Revolver will occur, (ii) for a reduction in commitments to $171.8 million and (iii) that the borrowing base under the Revolver is not subject to scheduled redetermination until May 15, 2016. Specifically, the extension period with respect to events of default is through 12:01 am on April 12, 2016, which can be further extended through 12:01 am on May 10, 2016 if certain conditions have been satisfied. The extension period can be terminated early upon certain triggering events.

The key conditions to the first extension (April 12, 2016) and entry to the Eleventh Amendment are: (i) termination of certain hedge agreements and application of the proceeds against the loans (which will result in a further reduction of our lenders' commitments), (ii) entry into control agreements over deposit accounts, subject to customary exceptions, (iii) payment of advisor fees, and (iv) agreement to certain changes to the Revolver, including increasing the interest rate by 1.00%, tightening certain restrictive covenants and agreeing that monthly hedge settlements will be applied against the loans (which will result in a further reduction in our lenders' commitments).

The key conditions to the second extension (May 10, 2016) are: (i) termination of certain additional hedges and application of most of the proceeds against the loans (which will result in a further reduction in our lenders' commitments)and (ii) no notification by the representative of the ad hoc committee of unsecured noteholders that they do not support such extension. For additional information regarding the Eleventh Amendment, please see Item 9B, "Other Information."

In January 2016, the Revolver was amended to (i) allow us to convert to or continue LIBOR loans without having to make a solvency representation and (ii) increase our mortgage requirement from 80 percent to 100 percent (subject to certain exceptions) of our proved reserves. In November 2015, in connection with the semi-annual redetermination, our lenders decreased their aggregate total commitment and borrowing base under the Revolver to $275 million due primarily to depressed commodity prices and our reduced capital program.

Suspension of Preferred Stock Dividends

In September 2015, we announced a suspension of quarterly dividends on our outstanding Series A Preferred Stock and Series B Preferred Stock for the quarter ended September 30, 2015. The suspension was extended through the quarter ended December 31, 2015. Our articles of incorporation provide that any unpaid dividends, including the unpaid dividends for the quarters ended September 30, 2015 and December 31, 2015 and any future unpaid dividends, will accumulate. For the year ended December 31, 2015, we accumulated a total of $10.7 million in unpaid preferred stock dividends. The suspension of quarterly dividends does not affect our business operations and does not cause an event of default under any of our debt agreements. Pursuant to the Eleventh Amendment, we are precluded from making dividend payments on our Series A and Series B Preferred Stock.

Sale of Assets

In October 2015, we sold certain non-core Eagle Ford properties for $12.5 million, net of transaction costs and customary closing adjustments. We recognized a loss of $9.5 million on this transaction in the fourth quarter of 2015.

In August 2015, we sold our East Texas assets and received cash proceeds of approximately $73 million, net of transaction costs and customary closing adjustments. The effective date of the sale was May 1, 2015 and we recognized a gain of approximately $43 million. The properties sold had net production of 1,898 BOEPD during the second quarter of 2015, consisting of 74 percent natural gas, 19 percent NGLs and seven percent crude oil.

The net proceeds from these transactions were used to pay down a portion of our outstanding borrowings under the Revolver.

Production and Development in the Eagle Ford

Our Eagle Ford production was 16,544 BOEPD during the three months ended December 31, 2015 with oil comprising 11,764 BOPD, or 71 percent, and NGLs and natural gas comprising approximately 16 percent and 13 percent. Our fourth quarter production represented an 11 percent decrease compared to 18,528 BOEPD during the three months ended September 30, 2015, of which 12,826 BOPD, or 69 percent, was crude oil, 17 percent was NGLs and 14 percent was natural gas. The sequential decline in production was attributable to our reduction in drilling activity.

During the three months ended December 31, 2015, we drilled and completed six gross (4.5 net) wells in the Eagle Ford for a total of 61 gross (38.6 net) wells for the full year. The last 11 wells that we drilled and completed were two-string lower Eagle Ford wells with slickwater stimulation. The average drilling and completion costs for these wells totaled approximately $5.2 million per well.

During the three months ended December 31, 2015, the wells that we drilled and completed had an average IP rate of over 1,600 BOEPD over an average of 19.5 frac stages, with 71 percent of production from crude oil, compared to an average of approximately 1,500 BOEPD over an average of 21.2 frac stages in the three months ended September 30, 2015. The average amount of proppant per stage for these was approximately 450,000 pounds and the average amount of proppant per lateral foot was approximately 2,020 pounds, compared to approximately 422,000 pounds per stage and 1,800 pounds per lateral foot in the three months ended September 30, 2015. Of the five gross wells that we have completed in 2016, three had IP rates in excess of 3,500 BOEPD with approximately 93 percent production from crude oil over an average of 27.7 frac stages. These particular wells are among the most productive wells we have drilled in the Eagle Ford thus far. We believe the strong improvement in early-time production rates is attributable to the use of slickwater stimulations, continued use of "zipper fracs" for alternating laterals on multi-well pads and increased frac intensity as measured by the increased proppant pumped per stage.

Financial Condition

Ability to Continue as a Going Concern

The precipitous decline in oil and natural gas prices during 2015 and into 2016 has had a significant adverse impact on our business, and as a result of our financial condition, our registered independent public accountants have issued an opinion with an explanatory paragraph expressing substantial doubt as to our ability to continue as a "going concern." The Revolver requires us to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. Furthermore, we have classified all of our total outstanding debt as short-term as of December 31, 2015, which represents a breach of the current ratio covenant under the Revolver. Pursuant to the Eleventh Amendment, we have received an agreement from our lenders that such default, together with certain other defaults, will not become events of default until April 12, 2016 (which can be further extended until May 10, 2016 if certain other conditions have been satisfied). For additional information regarding the Eleventh Amendment, please see Item 9B, "Other Information." If we do not obtain a waiver or other suitable relief from the lenders under the Revolver before the extension expires, there will exist an event of default under the Revolver. Even if we obtain such a waiver or other relief, we still believe we cannot comply with the leverage covenant during the next twelve months. If we cannot obtain from our lenders a waiver of such potential breach or an amendment of the leverage covenant, our breach would constitute an event of default that could result in an acceleration of substantially all of our outstanding indebtedness. We would not have sufficient capital to satisfy these obligations.

Liquidity

Our primary sources of liquidity have historically included cash from operating activities, borrowings under the Revolver, proceeds from the sales of assets and, from time to time, proceeds from capital market transactions, including the offering of debt and equity securities. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for our crude oil, NGL and natural gas products, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity and other supply chain dynamics, among other factors. As a result of continued low oil and natural gas prices during 2015 and into 2016, our liquidity has been significantly negatively impacted.

As of December 31, 2015, we had an aggregate amount of approximately $1.2 billion of debt outstanding. We will be required to pay interest on our senior notes in the amount of $87.6 million in 2016, including $10.9 million in April 2016 and $32.9 million in May 2016. Our ability to make those payments is severely in doubt. In 2015, we incurred a loss from operations of $1.6 billion, including an impairment charge of $1.4 billion. As of March 11, 2016, we had only $32.3 million in cash and cash equivalents. Pursuant to the Eleventh Amendment, the commitments under the Revolver were reduced to $171.8 million, which is equal to our currently outstanding loans ($170 million) and issued letters of credit ($1.8 million) under the Revolver. Because we do not have any unused commitment capacity, we will not be able to draw on the Revolver to pay our second quarter interest payments on our senior notes or for any other purpose. Furthermore, we are required, at the time of borrowing and as a condition to borrowing, to make certain representations to our lenders. We may not currently be able to make these representations, nor is it likely that we will be able to do so in the future unless we can restructure our debt obligations. There can be no assurance that we will be able to restructure our debt obligations. While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or to otherwise extend the maturity dates, and to cure any potential defaults under the agreements governing such debt, there is no assurance that any particular action or actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our debt agreements will be sufficient.

Moreover, our lenders may in the future exercise their right to redetermine our $275 million borrowing base under the Revolver. Pursuant to the Eleventh Amendment, any such redetermination will not occur until after May 15, 2016. If our borrowing base is redetermined below the amount of our outstanding borrowings, a deficiency will result, and any deficiency must be repaid within 60 days. For additional information regarding the Eleventh Amendment, please see Item 9B, "Other Information."

Capital Resources

Our business plan for 2016 reflects a suspension of our drilling program as a result of depressed commodity prices. Upon the resumption of a drilling program, if any, we expect to allocate substantially all of our capital expenditures to the Eagle Ford. We continually review our drilling and capital expenditure plans and may change the amount we spend, or the allocations, based on available opportunities, product pricing, industry conditions, cash from operating activities and the overall availability of capital. For a detailed analysis of our historical capital expenditures, see the *Cash Flows* discussion that follows.

Cash From Operating Activities. In addition to commodity price volatility, as discussed in detail below, our cash from operating activities is impacted by the timing of our working capital requirements. The most significant component thereof is the timing of payments made for drilling and completion capital expenditures and the related billing and collection of our partners' share thereof. This component can be substantial to the extent that we are the operator of lower working interest wells. In certain circumstances, we have and will continue to utilize capital cash calls to mitigate the burden on our working capital. In addition, we have been required to make prepayments for certain oilfield products and services due to the recent reduction in our credit standing.

We historically have actively managed our exposure to commodity price fluctuations by hedging the commodity price risk for a portion of our expected production, typically through the use of collar and swap contracts. The level of our hedging activity and duration of the instruments employed depend on our cash flow at risk, available hedge prices, the magnitude of our capital program and our operating strategy. During 2015, our commodity derivatives portfolio resulted in $137.5 million of net cash receipts related to lower than anticipated prices received for our crude oil production and $0.7 million of net cash receipts attributable to lower than anticipated prices received for our natural gas production. If commodity prices remain depressed, we anticipate that our derivative portfolio will continue to result in receipts from settlements for the remainder of 2016.

For 2016, we have hedged approximately 6,000 BOPD at weighted-average floor/swap prices of $80.41 per barrel. Our natural gas hedges have expired and we anticipate remaining unhedged with respect to natural gas production for 2016.

Revolver Borrowings. As of December 31, 2015, the Revolver provided for a revolving commitment and borrowing base of $275 million, including up to $20 million for the issuance of letters of credit. The borrowing base under the Revolver is re-determined semi-annually, and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base.

The Revolver is available to us for general purposes, including working capital, capital expenditures and acquisitions. The Revolver matures in September 2017. We had outstanding borrowings of $170 million and letters of credit of $1.8 million as of December 31, 2015. Pursuant to the Eleventh Amendment, the commitments under the Revolver were reduced to $171.8 million, which is equal to our currently outstanding loans ($170 million) and issued letters of credit ($1.8 million) under the Revolver. Because we do not have any unused commitment capacity, we will not be able to draw on the Revolver to pay our second quarter interest payments on our senior notes or for any other purpose. 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 under the agreements governing such debt, there is no assurance that any particular action or actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our debt agreements will be sufficient.

Moreover, our lenders may in the future exercise their right to redetermine our $275 million borrowing base under the Revolver. Pursuant to the Eleventh Amendment, any such redetermination will not occur until after May 15, 2016. If our borrowing base is redetermined below the amount of our outstanding borrowings, a deficiency will result, and any deficiency must be repaid within 60 days.

For additional information regarding the terms and covenants under the Revolver, see "*Capitalization*" discussion that follows. The following table summarizes our borrowing activity under the Revolver during the periods presented:

	Borrowings Outstanding		
	Weighted-Average	Maximum	Weighted-Average Rate
Three months ended December 31, 2015	$ 160,543	$ 170,000	2.5151%
Year ended December 31, 2015	$ 173,904	$ 232,000	2.1981%

Proceeds from Sales of Assets. We continually evaluate potential sales of non-core assets, including certain oil and gas properties and non-strategic undeveloped acreage, among others.

Capital Market Transactions. From time-to-time and under market conditions that we believe are favorable to us, we have undertaken capital market transactions, including the offering of debt and equity securities. Historically, we have entered into such transactions to facilitate acquisitions and to pursue opportunities to adjust our total capitalization.

Cash Flows

The following table summarizes our cash flows for the periods presented:

	Year Ended December 31, 2015	Year Ended December 31, 2014	Variance
Cash flows from operating activities			
Operating cash flows, net	$ 146,211	$ 373,362	$ (227,151)
Working capital changes (excluding interest, income taxes and restructuring and exit costs paid), net	(15,918)	8,282	(24,200)
Commodity derivative settlements received (paid), net:			—
Crude oil	137,488	(6,170)	143,658
Natural gas	681	(1,254)	1,935
Interest payments, net of amounts capitalized	(86,226)	(84,797)	(1,429)
Income taxes received (paid), net	714	(3,612)	4,326
Strategic and financial advisory costs paid	(3,693)	—	(3,693)
Drilling rig termination costs paid	(6,636)	—	(6,636)
Acquisition-related arbitration costs paid	—	(589)	589
Restructuring and exit costs paid	(3,318)	(2,498)	(820)
Net cash provided by operating activities	169,303	282,724	(113,421)
Cash flows from investing activities			
Capital expenditures – property and equipment	(364,844)	(774,139)	409,295
Acquisition and working capital-related settlements, net	—	33,712	(33,712)
Proceeds from sales of assets, net	85,189	313,933	(228,744)
Net cash used in investing activities	(279,655)	(426,494)	146,839
Cash flows from financing activities			
Proceeds (repayments) from revolving credit facility borrowings, net	135,000	(171,000)	306,000
Proceeds from the issuance of preferred stock, net	—	313,330	(313,330)
Payments made to induce conversion of preferred stock	—	(4,256)	4,256
Debt issuance costs paid	(744)	(151)	(593)
Dividends paid on preferred stock	(18,201)	(12,803)	(5,398)
Other, net	—	1,428	(1,428)
Net cash provided by financing activities	116,055	126,548	(10,493)
Net increase (decrease) in cash and cash equivalents	$ 5,703	$ (17,222)	$ 22,925

*Cash Flows From Operating Activities. C*ommodity prices declined substantially during 2015 resulting in lower realized cash receipts from our product revenues. Our working capital utilization increased during 2015 as we paid down a substantial level of accounts payable and accrued expenses in 2015 attributable to activities from 2014. In addition, we were required to make prepayments in the latter part of the fourth quarter of 2015 for certain oilfield services due to deterioration in our credit standing. During 2015, we paid early termination charges for the early release of four drilling rigs, of which $0.7 million had been accrued at the end of 2014. During 2015, we also incurred and paid higher professional fees and other consulting costs associated with our strategic initiatives, including our refinancing efforts and our search for a new chief executive officer. Restructuring and exit costs paid were higher during 2015 due primarily to the payment of termination and severance benefits of approximately $1.0 million in connection with reductions in headcount. Cash paid for interest, net of amounts capitalized, was higher during 2015 due primarily to higher average amounts outstanding under the Revolver. The overall decline in operating cash flows was partially offset by (i) cash settlements from our commodity derivatives portfolio during 2015 as compared to net payments during 2014 and (ii) the receipt of federal income tax refunds in 2015 as compared to federal and state income tax payments in 2014.

Cash Flows From Investing Activities. As illustrated in the tables below, our cash payments for capital expenditures were substantially lower during 2015 compared to 2014 due primarily to the reduction in our capital program including (i) reductions in the number of operated drilling rigs from eight at the beginning of 2015 to one by the end of the year, (ii) corresponding reductions in well completion and frac crews, (iii) lower pipeline and gathering infrastructure expenditures and (iv) the completion of our water system infrastructure project in 2014.

The following table sets forth costs related to our capital expenditure program for the periods presented:

	Year Ended December 31,	
	2015	2014
Oil and gas:		
Drilling and completion	$ 284,225	$ 667,385
Lease acquisitions and other land-related costs [1]	16,052	98,443
Geological and geophysical (seismic) costs	828	5,106
Pipeline, gathering facilities and other equipment	3,884	21,538
	304,989	792,472
Other – Corporate	562	1,463
Total capital program costs	$ 305,551	$ 793,935

[1] Includes site-preparation and other pre-drilling costs.

The following table reconciles the total costs of our capital expenditure program with the net cash paid for capital expenditures for additions to property and equipment as reported in our Consolidated Statements of Cash Flows for the periods presented:

	Year Ended December 31,	
	2015	2014
Total capital program costs	$ 305,551	$ 793,935
Decrease (increase) in accrued capitalized costs	55,660	(24,715)
Less:		
Exploration expenses charged to operations:		
Geological and geophysical (seismic)	(828)	(5,106)
Other, primarily delay rentals	(111)	(860)
Transfers from tubular inventory and well materials	(4,570)	(403)
Add:		
Tubular inventory and well materials purchased in advance of drilling	2,854	4,056
Capitalized interest	6,288	7,232
Total cash paid for capital expenditures	$ 364,844	$ 774,139

Our capital expenditures during 2015 and 2014 were partially offset by the receipt of net proceeds from the sale of assets. In 2015, we received approximately $85 million of net proceeds from the sale of our East Texas assets and certain non-core Eagle Ford properties. In 2014, we received approximately $314 million of net proceeds from the sale of our Selma Chalk assets in Mississippi, our natural gas gathering and gas lift assets in South Texas and the sale of rights to construct a crude oil gathering and intermediate transportation system in South Texas. We also received approximately $35 million, including interest of approximately $1 million, in 2014 with respect to the resolution of an acquisition-related arbitration matter. Approximately $34 million, excluding the interest component, was classified as an investing activity.

The following table sets forth the net proceeds received from the sale of assets for the periods presented:

	Year Ended December 31,	
	2015	2014
Oil and gas properties, net	$ 84,967	$ 70,818
Rights to construct an oil gathering system in South Texas, net	—	147,149
South Texas natural gas gathering and gas lift system, net	—	95,964
Tubular inventory, well materials and other, net	222	2
	$ 85,189	$ 313,933

Cash Flows From Financing Activities. We had net borrowings of $135 million under the Revolver in 2015 to fund our multi-rig capital program compared to net repayments of $171 million during 2014 using $313 million of net proceeds from the June 2014 offering of our Series B Preferred Stock and proceeds from sales of assets. We paid total dividends of $18.2 million for the Series A Preferred Stock and the Series B Preferred Stock in 2015 compared to $12.8 million in 2014. While we suspended payments on both preferred stock series in the third quarter of 2015, the total dividend payments were higher in 2015 due primarily to the Series B Preferred Stock being outstanding only in the second half of 2014. In 2014, we paid a total of $4.3 million to induce the conversion of approximately 30 percent of the outstanding shares of the Series A Preferred Stock. We paid issuance costs in 2015 and 2014 associated with amendments to the Revolver including $0.7 million in 2015 and $0.2 million in 2014. We also received proceeds of $1.4 million during 2014 from the exercise of stock options.

Capitalization

The following table summarizes our total capitalization as of the dates presented:

	As of December 31,	
	2015	2014
Revolving credit facility	$ 170,000	$ 35,000
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	775,000
Total debt	1,245,000	1,110,000
Shareholders' equity [1]	(915,121)	675,817
	$ 329,879	$ 1,785,817
Debt as a % of total capitalization	377%	62%

[1] Includes 3,915 and 7,945 shares of the Series A Preferred Stock and 27,551 and 32,500 shares of the Series B Preferred Stock as of December 31, 2015 and 2014. Both series of preferred stock have a liquidation preference of $10,000 per share representing a total of $314.7 million and $404.4 million as of December 31, 2015 and 2014.

Revolving Credit Facility. As of December 31, 2015, borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from LIBOR, as adjusted for statutory reserve requirements for Eurocurrency liabilities, or Adjusted LIBOR, plus an applicable margin (ranging from 1.500% to 2.500%) or (ii) the greater of (a) the prime rate, (b) the federal funds effective rate plus 0.5% or (c) the one-month Adjusted LIBOR plus 1.0% (clauses (a), (b) and (c)), or the Base Rate, plus, in each case, an applicable margin (ranging from 0.500% to 1.500%). Pursuant to the Eleventh Amendment, the applicable margin for borrowings bearing interest as a rate derived from (a) LIBOR was increased 1.00% (to a range of 2.500% to 3.500%) and (b) the Base Rate was increased by 1.00% (to a range of 1.500% to 2.500%). In each case, the applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity. As of December 31, 2015, the actual interest rate applicable to the Revolver was 4.5% which is derived from the prime rate of 3.5% plus an applicable margin of 1.0%. The applicable interest rate was re-set on January 12, 2016 to a one-month LIBOR-based rate of 2.4375% (Adjusted LIBOR rate of 0.4375% plus an applicable margin of 2.0%.) Commitment fees are charged at 0.375% to 0.500% on the undrawn portion of the Revolver depending on our ratio of outstanding borrowings to the available Revolver capacity. As of December 31, 2015, commitment fees were being charged at a rate of 0.375%.

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries, or the Guarantor Subsidiaries. The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of the equity interests in the Guarantor Subsidiaries.

2019 Senior Notes. The 2019 Senior Notes, which were issued at par in April 2011, bear interest at an annual rate of 7.25% which is payable on April 15 and October 15 of each year. We may redeem all or part of the 2019 Senior Notes at a redemption price of 103.625% of the principal amount reducing to 100% in June 2017 and thereafter. The 2019 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The 2019 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries. Additionally, the 2019 Senior Notes contain certain cross-default provisions, which would result in an event of default under the notes if our lenders under the Revolver accelerate the Revolver obligations. Such event of default, if it occurs, would permit the noteholders to accelerate the 2019 Senior Notes.

2020 Senior Notes. The 2020 Senior Notes, which were issued at par in April 2013, bear interest at an annual rate of 8.50% which is payable on May 1 and November 1 of each year. Beginning in May 2017, we may redeem all or part of the 2020 Senior Notes at a redemption price of 104.250% of the principal amount reducing to 100% in May 2019 and thereafter. The 2020 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The 2020 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries. Additionally, the 2020 Senior Notes contain certain cross-default provisions, which would result in an event of default under the notes if our lenders under the Revolver accelerate the Revolver obligations. Such event of default, if it occurs, would permit the noteholders to accelerate the 2020 Senior Notes.

Series A and Series B Preferred Stock. The annual dividend on each share of the Series A Preferred Stock and Series B Preferred Stock is 6.00% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on each of January 15, April 15, July 15 and October 15 of each year. We may, at our option, pay dividends in cash, common stock or a combination thereof; however, the utilization of common stock to pay dividends on Series B Preferred Stock would require shareholder approval. In addition, cash payment of dividends may be limited by certain financial covenants under the Revolver. See "*Covenant Compliance*" that follows.

Each share of the Series A Preferred Stock and Series B Preferred Stock is convertible, at the option of the holder, into a number of shares of our common stock equal to the liquidation preference of $10,000 divided by the applicable conversion prices, which is initially $6.00 per share for the Series A Preferred Stock and $18.34 per share for the Series B Preferred Stock, subject in each case to specified anti-dilution adjustments. The initial conversion rate is equal to 1,666.67 shares of our common stock for each share of the Series A Preferred Stock and 545.17 shares of our common stock for each share of the Series B Preferred Stock. The Series A Preferred Stock and Series B Preferred Stock are not redeemable for cash by us or the holders at any time. At any time on or after October 15, 2017 in the case of the Series A Preferred Stock and July 15, 2019 in the case of the Series B Preferred Stock, we may, at our option, cause all outstanding shares of the Series A Preferred Stock and Series B Preferred Stock, respectively, to be automatically converted into shares of our common stock at the then-applicable conversion prices for each series if the closing price of our common stock exceeds 130% of the then-applicable conversion price for a specified period prior to conversion. If a holder elects to convert shares of the Series A Preferred Stock and Series B Preferred Stock upon the occurrence of certain specified fundamental changes, we may be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option value.

In September 2015, we announced a suspension of quarterly dividends on the Series A Preferred Stock and Series B Preferred Stock for the quarter ended September 30, 2015. The suspension was extended through December 31, 2015. Our articles of incorporation provide that any unpaid dividends will accumulate, including the unpaid dividends for the quarters ended September 30, 2015 and December 31, 2015 and any future unpaid dividends. If we do not pay dividends on our Series A and B Preferred Stock for six quarterly periods, whether consecutive or non-consecutive, the holders of the shares of both series of preferred stock, voting together as a single class, will have the right to elect two additional directors to serve on our board of directors until all accumulated and unpaid dividends are paid in full. Pursuant to the Eleventh Amendment, we are precluded from making dividend payments on our Series A and Series B Preferred Stock.

While the accumulation does not result in presentation of a liability on the balance sheet, the accumulated dividends are added to our net loss in the determination of the loss attributable to common shareholders and the related loss per share. For the quarters ended September 30, 2015 and December 31, 2015, we accumulated a total of $10.7 million in unpaid preferred stock dividends, including $1.7 million attributable to the Series A Preferred Stock and $9.0 million attributable to the Series B Preferred Stock.

Covenant Compliance. The Revolver requires us to maintain certain financial and non-financial covenants. These covenants impose limitations on our ability to pay dividends as well as our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, or enter into a merger or sale of our assets, including the sale or transfer of interests in our subsidiaries, among other requirements.

The Revolver requires us to maintain certain financial covenants as follows:

- Total debt to EBITDAX, each as defined in the Revolver, for any four consecutive quarters may not exceed 4.75 to 1.0 for periods through March 31, 2016, 5.25 to 1.0 for periods through June 30, 2016, 5.50 to 1.0 for periods through December 31, 2016, 4.50 to 1.0 for periods through March 31, 2017 and 4.0 to 1.0 through maturity in September 2017. EBITDAX, which is a non-GAAP measure, generally means net income plus interest expense, taxes, depreciation, depletion and amortization expenses, exploration expenses, impairments and other non-cash charges or losses.
- Credit exposure to EBITDAX for any four consecutive quarters may not exceed 2.75 to 1.0 for periods ending after March 31, 2015 through March 31, 2017. Credit exposure consists of all outstanding borrowing under the Revolver plus any outstanding letters of credits.
- The current ratio, as of the last day of any quarter, may not be less than 1.0 to 1.0. The current ratio is generally the ratio of current assets to current liabilities. Current assets and current liabilities attributable to derivative instruments are excluded. In addition, current assets include the amount of any unused commitment under the Revolver.

In addition, we are precluded from the payment of cash dividends on our outstanding convertible preferred stock if the total debt to EBITDAX ratio exceeds 5.0 to 1.0. Pursuant to the Eleventh Amendment, we are no longer permitted to make payment of dividends on our outstanding convertible preferred stock or common stock.

The indentures governing our senior notes include an incurrence test which is determined by an interest coverage ratio, as defined in the indentures. The interest coverage ratio may not be less than 2.25 times consolidated EBITDAX, a non-GAAP measure.

The following table summarizes the actual results of our financial compliance under the Revolver and senior note indentures as of and for the year ended December 31, 2015:

Description	Required Covenant	Actual Results
Total debt to EBITDAX	< 4.75 to 1	4.54 to 1
Credit exposure to EBITDAX	< 2.75 to 1	0.63 to 1
Current ratio	> 1.00 to 1	0.13 to 1
Interest coverage	> 2.25 to 1	2.56 to 1

The precipitous decline in oil and natural gas prices during 2015 and into 2016 has had a significant adverse impact on our business, and as a result of our financial condition, our registered independent public accountants have issued an opinion with an explanatory paragraph expressing substantial doubt as to our ability to continue as a "going concern." The Revolver requires us to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. Furthermore, we have classified all of our total outstanding debt as short-term as of December 31, 2015, which represents a breach of the current ratio covenant under the Revolver. Pursuant to the Eleventh Amendment, we have received an agreement from our lenders that such breach, together with the "going concern" default and certain other defaults, will not become events of default until April 12, 2016 (which can be further extended until May 10, 2016 if certain conditions have been satisfied). For additional information regarding the Eleventh Amendment, please see Item 9B, "Other Information." If we do not obtain a waiver or other suitable relief from the lenders under the Revolver prior to the expiration of the extension, there will exist an event of default under the Revolver. Even if we obtain such a waiver or other relief, we still believe we cannot comply with the leverage covenant during the next twelve months. If we cannot obtain from our lenders a waiver of such potential breach or an amendment of the leverage covenant, our breach would constitute an event of default that could result in an acceleration of substantially all of our outstanding indebtedness. We would not have sufficient capital to satisfy these obligations.

Additionally, pursuant to the Eleventh Amendment, the commitments under the Revolver were reduced to $171.8 million, which is equal to our currently outstanding loans ($170 million) and issued letters of credit ($1.8 million) under the Revolver. Because we do not have any unused commitment capacity, we will not be able to draw on the Revolver to pay our second quarter interest payments on our senior notes or for any other purpose. Moreover, our lenders may in the future exercise their right to redetermine our $275 million borrowing base under the Revolver. Pursuant to the Eleventh Amendment, any such redetermination will not occur until after May 15, 2016. If our borrowing base is redetermined below the amount of our outstanding borrowings, a deficiency will result, and any deficiency must be repaid within 60 days.

Results of Operations

Substantial components of our year-to-year variances are due to the effects of property divestitures. In 2015, we sold all of our interests in the Haynesville Shale and Cotton Valley in East Texas and in 2014 we sold all of our interests in the Selma Chalk in Mississippi. These non-core assets were primarily focused on natural gas production. In the discussion and analysis that follows, the term "Divested properties" refers to the production, revenues and expenses associated with our former assets and operations in East Texas and Mississippi. In 2015, we also sold various non-core properties in our South Texas and Mid-Continent regions of operations.

Production

The following tables set forth a summary of our total and daily production volumes by product and geographic region for the periods presented:

	Total Production					Average Daily Production				
	Year Ended December 31,			2015 vs.	2014 vs.	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013	2015	2014	2013	2014	2013
Crude oil (MBbl & Bbl/day)	4,923	4,644	3,435	279	1,209	13,523	12,723	9,412	800	3,311
NGLs (MBbl & Bbl/day)	1,381	1,110	982	272	128	3,893	3,040	2,692	853	348
Natural gas (MMcf & MMcf/day)	9,713	13,085	14,435	(3,372)	(1,351)	29	36	40	(6)	(4)
Total (MBOE & BOE/day)	7,923	7,934	6,824	(11)	1,111	22,323	21,738	18,696	585	3,043
% Change									3%	16%

	Year Ended December 31,			2015 vs.	2014 vs.	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013	2015	2014	2013	2014	2013
			(MBOE)					(BOE per day		
South Texas [1]	6,995	5,913	4,091	1,082	1,823	19,165	16,201	11,208	2,964	4,994
Mid-Continent and other [2]	479	765	962	(286)	(197)	1,311	2,096	2,636	(785)	(540)
Divested properties [3]	449	1,256	1,771	(807)	(515)	1,847	3,441	4,852	(1,594)	(1,411)
Total	7,923	7,934	6,824	(11)	1,111	22,323	21,738	18,696	585	3,043
% Change									3%	16%

[1] Includes total production and average daily production of approximately 92 MBOE (303 BOEPD), 96 MBOE (264 BOEPD) and 33 MBOE (90 BOEPD) for 2015, 2014 and 2013, respectively, attributable to non-core Eagle Ford properties that we sold in October 2015.

[2] Includes total production and average daily production of approximately 19 MBOE (61 BOEPD), 22 MBOE (61 BOEPD) and 29 MBOE (81 BOEPD) for 2015, 2014 and 2013, respectively, attributable to certain Mid-Continent properties that we sold in October 2015. Also includes total production and average daily production of approximately 22 MBOE (60 BOEPD), 24 MBOE (66 BOEPD) and 25 MBOE (67 BOEPD) for 2015, 2014 and 2013, respectively, attributable to our three active Marcellus Shale wells.

[3] Includes total production and average daily production of approximately 449 MBOE (1,847 BOEPD), 844 MBOE (2,311 BOEPD) and 1,020 MBOE (2,794 BOEPD) in 2015, 2014 and 2013, respectively, attributable to our East Texas assets that were sold in August 2015. Also includes total production and average daily production of approximately 412 MBOE (1,946 BOEPD) and 751 MBOE (2,058 BOEPD) in 2014 and 2013 attributable to our Mississippi assets that were sold in July 2014.

2015 vs. 2014. Total production was essentially unchanged during the year ended December 31, 2015 compared to 2014. Production from the continued development of our Eagle Ford assets in South Texas offset natural production declines and the sale of our East Texas properties in August 2015. Approximately 80 percent of total production during 2015 was attributable to oil and NGLs, which represents an increase of approximately 10 percent over 2014. During 2015, our Eagle Ford production represented approximately 88 percent of our total production compared to approximately 74 percent during 2014. During 2015, we turned in line 61 gross Eagle Ford wells compared to 93 gross wells that were brought on line during 2014. A substantial majority of these wells were brought on line during the first half of 2015 at a time when we were operating as many as eight drilling rigs.

2014 vs. 2013. Total production increased during the year ended December 31, 2014 compared to 2013 due primarily to development of our Eagle Ford properties. The increase was partially offset by natural production declines in the South Texas, Mid-Continent, East Texas and Mississippi regions, as well as the sale of our Mississippi properties in July 2014. Approximately 73 percent of total production during 2014 was attributable to oil and NGLs, which represents an increase of approximately 30 percent over 2013. During 2014, our Eagle Ford production represented approximately 74 percent of our total production compared to approximately 60 percent from this play during 2013. During 2014, we turned in line 93 gross wells in the Eagle Ford as compared to 59 gross wells that were brought on line during 2013.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product and geographic region for the periods presented:

	Total Product Revenues					Revenue per Unit of Volume				
	Year Ended December 31,			2015 vs.	2014 vs.	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013	2015	2014	2013	2014	2013
Crude oil (Total & $/Bbl)	$ 220,596	$ 420,286	$ 347,407	$ (199,690)	$ 72,879	$ 44.81	$ 90.50	$ 101.13	$ (45.69)	$ (10.63)
NGLs (Total & $/Bbl)	16,905	34,552	30,748	(17,647)	3,804	12.24	31.14	31.30	(18.90)	(0.16)
Natural gas (Total & $/Mcf)	25,479	58,044	52,538	(32,565)	5,506	2.62	4.44	3.64	(1.82)	0.80
Total (Total & $/BOE)	$ 262,980	$ 512,882	$ 430,693	$ (249,902)	$ 82,189	$ 33.19	$ 64.64	$ 63.11	$ (31.45)	$ 1.53
% Change									(49)%	2%

	Year Ended December 31,			2015 vs.	2014 vs.	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013	2015	2014	2013	2014	2013
						($ per BOE)				
South Texas [1]	$ 244,749	$ 440,566	$ 346,454	$ (195,817)	$ 94,112	$ 34.99	$ 74.50	$ 84.69	$ (39.51)	$ (10.19)
Mid-Continent and other [2]	10,071	32,125	37,131	(22,054)	(5,006)	21.03	41.99	38.60	(20.96)	3.39
Divested properties [3]	8,160	40,191	47,108	(32,031)	(6,917)	18.17	32.00	26.60	(13.83)	5.40
Total	$ 262,980	$ 512,882	$ 430,693	$ (249,902)	$ 82,189	$ 33.19	$ 64.64	$ 63.11	$ (31.45)	$ 1.53
% Change									(49)%	2%

[1] Includes revenues of $4.3 million, $7.8 million and $3.2 million for 2015, 2014 and 2013, respectively, attributable to non-core Eagle Ford properties that we sold in October 2015.

[2] Includes revenues of $0.4 million, $0.7 million and $1.0 million attributable to certain Mid-Continent properties that we sold in October 2015 as well as revenues of $0.2 million, $0.5 million and $0.5 million attributable to the Marcellus Shale for 2015, 2014 and 2013, respectively.

[3] Includes revenues of $8.2 million, $28.2 million and $28.6 million attributable to East Texas for 2015, 2014 and 2013, respectively, and $12.0 million and $18.5 million attributable to Mississippi for 2014 and 2013.

The following table provides an analysis of the changes in our revenues for the periods presented:

	2015 vs. 2014 Revenue Variance Due to			2014 vs. 2013 Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ 25,263	$ (224,953)	$ (199,690)	$ 122,219	$ (49,340)	$ 72,879
NGLs	8,454	(26,101)	(17,647)	3,987	(183)	3,804
Natural gas	(14,957)	(17,608)	(32,565)	(4,962)	10,468	5,506
	$ 18,760	$ (268,662)	$ (249,902)	$ 121,244	$ (39,055)	$ 82,189

Effects of Derivatives

In 2015, we received $138.2 million from cash settlements of oil and gas derivatives compared to net payments of $7.4 million and $1.0 million in 2014 and 2013, respectively. The following table reconciles crude oil and natural gas revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31,		Increase	Year Ended December 31,		Favorable
	2015	2014	(Unfavorable)	2014	2013	(Unfavorable)
Crude oil revenues as reported	$ 220,596	$ 420,286	$ (199,690)	$ 420,286	$ 347,407	$ 767,693
Derivative settlements, net	137,488	(6,170)	143,658	(6,170)	(2,624)	(8,794)
	$ 358,084	$ 414,116	$ (56,032)	$ 414,116	$ 344,783	$ 758,899
Crude oil prices per Bbl, as reported	$ 44.81	$ 90.51	$ (45.70)	$ 90.51	$ 101.14	$ (10.63)
Derivative settlements per Bbl	27.93	(1.33)	29.26	(1.33)	(0.76)	(0.57)
	$ 72.74	$ 89.18	$ (16.44)	$ 89.18	$ 100.38	$ (11.20)
Natural gas revenues as reported	$ 25,479	$ 58,044	$ (32,565)	$ 58,044	$ 52,538	$ 5,506
Derivative settlements, net	681	(1,254)	1,935	(1,254)	1,582	(2,836)
	$ 26,160	$ 56,790	$ (30,630)	$ 56,790	$ 54,120	$ 2,670
Natural gas prices per Mcf, as reported	$ 2.62	$ 4.44	$ (1.82)	$ 4.44	$ 3.64	$ 0.80
Derivative settlements per Mcf	0.07	(0.10)	0.17	(0.10)	0.11	(0.21)
	$ 2.69	$ 4.34	$ (1.65)	$ 4.34	$ 3.75	$ 0.59

Gain (Loss) on Sales of Property and Equipment

In 2015, we recognized a gain of approximately $43 million on the sale of our East Texas assets. Additionally, in connection with an amendment to our crude oil gathering agreement with Republic which included a pricing concession, we recognized $8.4 million of a gain that was previously deferred and being recognized over the term of the underlying agreement. In 2015, we also recognized $0.4 million of deferred gain from the 2014 sale of our natural gas gathering and gas lift assets in South Texas. These gains were partially offset by a loss of $9.5 million from the sale of certain non-core Eagle Ford properties and a combined loss of $1.2 million from other sale transactions and post-closing adjustments attributable to prior year asset sales.

In 2014, we recognized a gain of $63.0 million in connection with the sale to Republic of rights to construct a crude oil gathering and intermediate transportation system and a gain of $57.1 million on the sale of our natural gas gathering and gas lift assets in South Texas, including $56.7 million recognized upon the closing of the sale and $0.4 million attributable to the deferred portion of the gain.

In 2013, we recognized losses of $0.3 million related primarily to certain post-closing adjustments for asset sales that occurred in prior years. In addition, we recognized several individually insignificant gains and losses on the sale of property, equipment, tubular inventory and well material.

Other Revenues

2015 vs. 2014. Other revenues, which includes gathering, transportation, marketing, compression, water supply and disposal fees that we charge to other parties, net of marketing and related expenses as well as accretion of our unused firm transportation obligation, decreased during 2015 from 2014. Certain of these revenue sources declined following the sale of our assets in East Texas where we provided services to other producers. The declines were partially offset by revenue from water disposal facilities in Eagle Ford that were brought on-line in 2015.

2014 vs. 2013. Other revenues increased during 2014 from 2013 due primarily to income related to water supply which began in April 2014. The increase was partially offset by the effect of a $1.6 million gain in 2013 attributable to the sale of certain proprietary seismic data.

Lease Operating Expenses

	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013
				Favorable (unfavorable)	
Lease operating	$ 42,428	$ 48,298	$ 35,461	$ 5,870	$ (12,837)
Per unit of production ($/BOE)	$ 5.36	$ 6.09	$ 5.20	$ 0.73	$ (0.89)
% Change per unit of production				12%	(17)%

2015 vs. 2014. Lease operating expense, or LOE, in our South Texas region increased $6.2 million on an absolute basis commensurate with higher production. This regional increase was also due to higher gas lift and compression costs as well as down-hole repairs, particularly in the first half of 2015. The increase in South Texas LOE for 2015 was partially offset by a $1.7 million decline in other areas due primarily to lower production volumes. The sale of our East Texas assets in 2015 and Mississippi assets in 2014 resulted in a total decrease of $10.4 million in LOE costs for 2015 compared to 2014.

2014 vs. 2013. LOE in our South Texas region increased $11.4 million on an absolute basis during 2014 compared to 2013 due primarily to higher production volume during 2014. We began to incur costs for certain compression and gas lift services provided by American Midstream Partners, LP, or AMID, beginning in February 2014 subsequent to their purchase of our natural gas gathering and gas lift assets in South Texas. While most of our other volume-based costs, including chemical, water disposal and labor costs also increased on an absolute basis, we experienced decreases on a per-unit basis due to 45 percent higher production volumes. We also experienced higher workover and subsurface maintenance costs in South Texas in 2014 compared to 2013. Higher LOE of $2.6 million in East Texas in 2014 compared to 2013 was due primarily to higher workover and subsurface maintenance costs while LOE in the Mid-Continent and other region declined marginally due to lower production volumes. Finally, the sale of our Mississippi assets in 2014 resulted in a decrease in LOE of $1.1 million in 2014 compared to 2013.

Gathering Processing and Transportation

	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013
				Favorable (unfavorable)	
Gathering, processing and transportation	$ 23,815	$ 18,294	$ 12,839	$ (5,521)	$ (5,455)
Per unit production ($/BOE)	$ 3.01	$ 2.31	$ 1.88	$ (0.70)	$ (0.43)
% Change per unit of production				(30)%	(23)%

2015 vs. 2014. Gathering, processing and transportation, or GPT, charges increased $6.4 million during 2015 compared to 2014 due primarily to higher South Texas production volumes including an increase in NGL and natural gas production from our Eagle Ford wells. NGL and natural gas production increased to 17 percent and 14 percent of total South Texas production in 2015 compared to 13 percent and 12 percent in 2014. This increase was partially offset by $0.5 million of lower GPT charges for our Mid-Continent and other region commensurate with a decline in production volume from that region. We also experienced further decreases of $0.4 million resulting from the sale of our East Texas assets in 2015 and our Mississippi assets in 2014.

2014 vs. 2013. GPT charges increased $7.8 million during 2014 compared to 2013 due primarily to additional gathering and compression charges for natural gas and NGL production in the South Texas region attributable to the gathering, compression and gas lift services agreement with AMID which began in February 2014, partially offset by a decrease of $2.3 million due to the effect of lower natural gas and NGL production volume in our East Texas and Mid-Continent and other regions as well as a decrease of $0.1 million due to the effect of lower natural gas production following the sale of our Mississippi assets in July 2014.

Production and Ad Valorem Taxes

	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013
				Favorable (unfavorable)	
Production/severance taxes	$ 11,796	$ 22,567	$ 17,355	$ 10,771	$ (5,212)
Ad valorem taxes	4,486	5,423	5,049	937	(374)
	$ 16,282	$ 27,990	$ 22,404	$ 11,708	$ (5,586)
Per unit production ($/BOE)	$ 2.06	$ 3.53	$ 3.28	$ 1.47	$ (0.25)
Production/severance tax rate	4.5%	4.4%	4.0%		
% Change per unit of production				42%	(8)%

2015 vs. 2014. Production taxes in the South Texas region declined substantially during 2015 compared to 2014 due primarily to significantly lower prices for commodity products despite increased production volumes. Production declines in all other regions as well as the sale of our East Texas assets in 2015 and our Mississippi assets in 2014 also contributed to the decline. Ad valorem taxes declined during 2015 compared to 2014 due to lower assessment values impacted by lower overall commodity prices.

2014 vs. 2013. Production taxes increased during 2014 compared to 2013 due primarily to increased crude oil production in the South Texas region, which carries a higher severance tax rate than our other operating regions, partially offset by severance tax audit refunds for natural gas production in Mississippi attributable to periods prior to the sale of those properties.

General and Administrative

The following table sets forth the components of general and administrative expenses for the periods presented:

	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013	2015 vs. 2014	2014 vs. 2013
				Favorable (unfavorable)	
Recurring general and administrative expenses	$ 32,353	$ 39,106	$ 40,410	$ 6,753	$ 1,304
Share-based compensation (liability-classified)	(711)	4,519	4,116	5,230	(403)
Share-based compensation (equity-classified)	4,540	3,627	5,781	(913)	2,154
Significant non-recurring expenses:					
Strategic and financial advisory costs	6,189	—	—	(6,189)	—
ERP system development costs	—	1,154	655	1,154	(499)
Acquisition-related costs	—	589	3,029	589	2,440
Restructuring expenses	957	10	7	(947)	(3)
	$ 43,328	$ 49,005	$ 53,998	$ 5,677	$ 4,993
Per unit of production ($/BOE)	$ 5.47	$ 6.18	$ 7.91	$ 0.71	$ 1.74
Per unit of production excluding liability and equity-classified share-based compensation ($/BOE)	$ 4.99	$ 5.15	$ 6.46	$ 0.16	$ 1.31
Per unit of production excluding share-based compensation and other non-recurring expenses identified above ($/BOE)	$ 4.08	$ 4.93	$ 5.92	$ 0.85	$ 0.99

2015 vs. 2014. Our total general and administrative, or G&A, expenses decreased on both an absolute and per unit basis during 2015 compared to 2014. Decreases in recurring G&A expenses were due primarily to lower payroll and benefits attributable to lower employee headcount, substantially lower cash-based incentive compensation, reduced travel and entertainment and lower corporate support costs.

Liability-classified share-based compensation is attributable to our performance-based restricted stock units, or PBRSUs, and represents mark-to-market charges associated with the change in fair value of the outstanding PBRSU grants. Our common stock performance relative to a defined peer group was less favorable during 2015 compared to 2014 resulting in a reduction in liability-classified share-based compensation.

Equity-classified share-based compensation charges attributable to stock options and restricted stock units, which represent non-cash expenses, increased during 2015 compared to 2014 due primarily to a higher weighting of share-based awards over cash-based awards with respect to the compensation program for our senior management.

In 2015, we incurred professional fees and other consulting costs associated with our ongoing strategic initiatives, including our refinancing efforts and our search for a new chief executive officer. Included in the total $6.2 million for these costs was $5.5 million attributable to a proposed first lien debt financing transaction that was terminated in December 2015. In connection with our ongoing efforts to adjust the scale of our administrative cost structure, we terminated a combined total of 26 employees, or approximately 16 percent of our total headcount from year-end 2014 levels, in two separate actions taken in May and October of 2015. We paid approximately $1 million in severance and termination benefits in connection with these actions. In 2014, we incurred certain costs not eligible for capitalization, including post-implementation support and training with respect to our ERP system replacement. In 2014, we also incurred costs including legal and litigation support fees attributable to an acquisition-related arbitration matter.

2014 vs. 2013. Our total general and administrative expenses decreased on both an absolute and per unit basis during 2014 compared to 2013, reflecting lower incentive compensation costs partially offset by higher employee benefits and occupancy costs. The increase in liability-classified share-based compensation for 2014 compared to 2013 was attributable to favorable performance of our common stock relative to a defined peer group. Equity-classified share-based compensation charges decreased during 2014 compared to 2013 due primarily to fewer employees receiving grants and the elimination of retirement age-eligible, or grant-date vesting provisions. In 2013, we incurred preliminary project analysis and other non-capitalizable costs associated with our ERP system replacement. In 2013, we also incurred acquisition-related transaction costs, including advisory, legal, due diligence and other professional fees.

Exploration

The following table sets forth the components of exploration expenses for the periods presented:

	Year Ended December 31, 2015	2014	2013	2015 vs. 2014	2014 vs. 2013
				Favorable (unfavorable)	
Unproved leasehold amortization	$ 5,759	$ 10,346	$ 17,451	$ 4,587	$ 7,105
Drilling rig termination charges	5,885	751	—	(5,134)	(751)
Geological and geophysical (seismic) costs	828	5,106	2,882	4,278	(2,224)
Other, primarily delay rentals	111	860	661	749	(199)
	$ 12,583	$ 17,063	$ 20,994	$ 4,480	$ 3,931

2015 vs. 2014. The sale of our East Texas assets in 2015 and Mississippi assets in 2014 resulted in a $3.0 million reduction in unproved leasehold amortization in 2015 compared to 2014. The declining leasehold asset base subject to amortization, primarily in the Mid-Continent and other region, accounted for the remainder of the decrease in amortization. We incurred early termination charges in connection with the release of three drilling rigs in Eagle Ford during 2015 compared to one early release in 2014. Seismic and delay rental costs declined in 2015 compared to 2014 due to a significant decrease in our capital program and limited exploration activity.

2014 vs. 2013. Unproved leasehold amortization decreased during 2014 compared to 2013 due primarily to the classification of our Eagle Ford unproved property as a “significant leasehold” effective July 1, 2013. Accordingly, this unproved acreage was no longer subject to systematic amortization. Geological and geophysical costs increased due to higher seismic data acquisition costs in South Texas. As referenced above, we also incurred a charge in 2014 in connection with the early termination of a drilling rig contract. Delay rentals increased due primarily to a larger inventory of undeveloped acreage in South Texas.

Depreciation, Depletion and Amortization (DD&A)

The following table sets forth the nature of the DD&A variances for the periods presented:

	Year Ended December 31, 2015	2014	2013	2015 vs. 2014	2014 vs. 2013
				Favorable (unfavorable)	
DD&A expense	$ 334,479	$ 300,299	$ 245,594	$ (34,180)	$ (54,705)
DD&A rate ($/BOE)	$ 42.22	$ 37.85	$ 35.99	$ (4.37)	$ (1.86)

	DD&A Variance due to: Production	Rates	Total
2015 to 2014 DD&A variance due to:	$ 427	$ (34,607)	$ (34,180)
2014 to 2013 DD&A variance due to:	$ (39,955)	$ (14,750)	$ (54,705)

2015 vs. 2014. Higher depletion rates attributable to the higher-cost drilling program in the Eagle Ford, followed by a downward revision of reserves in that region, were the primary factor leading to the increase in DD&A expense recognized in 2015 compared to 2014.

2014 vs. 2013. Higher overall production volumes as well as higher depletion rates associated with oil and NGL production in 2014 were the primary factors affecting the increase in DD&A expense compared to 2013. Our average DD&A rate increased due to the higher-cost oil drilling program in the Eagle Ford and the downward revisions of proved undeveloped reserves in East Texas.

Impairments

The significant deterioration of commodity prices throughout 2015, as reflected in the future strip pricing as of December 31, 2015, triggered an impairment of approximately $1.4 billion to our proved and unproved Eagle Ford properties and required us to reduce their carrying value to a fair value of approximately $312 million. In 2015, we also recorded an impairment charge of $1.1 million attributable to surplus tubular inventory and well materials. In 2014, we recognized oil and gas asset impairments of: (i) $667.8 million in the East Texas, Granite Wash and Marcellus regions due to the decline in commodity prices in the fourth quarter of 2014, (ii) $6.1 million in connection with an uneconomic field drilled in the Mid-Continent region and (iii) $117.9 million with respect to our Selma Chalk assets in Mississippi triggered by the disposition of those properties. In 2013, we recognized oil and gas asset impairments of: (i) $121.8 million in the Granite Wash, (ii) $9.5 million in the Marcellus Shale and (iii) $0.9 million in the Selma Chalk, in each case due primarily to declines in natural gas prices.

Interest Expense

The following table summarizes the components of our interest expense for the periods presented:

	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013
				Favorable (unfavorable)	
Interest on borrowings and related fees	$ 92,490	$ 91,866	$ 80,263	$ (624)	$ (11,603)
Amortization of debt issuance costs	4,749	4,197	3,413	(552)	(784)
Accretion of original issue discount	—	—	431	—	431
Capitalized interest	(6,288)	(7,232)	(5,266)	(944)	1,966
	$ 90,951	$ 88,831	$ 78,841	$ (2,120)	$ (9,990)
Weighted-average debt outstanding	$ 1,246,342	$ 1,206,831	$ 1,026,732	$ (39,511)	$ (180,099)
Weighted average interest rate	7.42%	7.61%	7.82%		

2015 vs. 2014. Interest expense increased during 2015 compared to 2014 due primarily to (i) higher weighted-average debt outstanding under the Revolver, (ii) higher amortization of debt issuance costs for the 2019 Senior Notes and the 2020 Senior Notes, based on the effective interest method of amortization, (iii) higher amortization of Revolver issuance costs due to costs incurred to amend the Revolver in the fourth quarter of 2014 and second quarter of 2015 and (iv) lower capitalized interest as the balance of capital projects subject to capitalization declined commensurate with the overall reduction in our 2015 capital program. The weighted-average interest rate declined during 2015 compared to 2014 due to a higher weighting of borrowings under the Revolver to total debt outstanding in 2015.

2014 vs. 2013. Interest expense increased during 2014 compared to 2013 due primarily to (i) higher weighted-average debt outstanding following the issuance of the 2020 Senior Notes in April 2013 and (ii) higher average outstanding borrowings under the Revolver. These increase were partially offset by (i) higher capitalized interest resulting from the significant increase in the value of our proved undeveloped and unproved properties following our 2013 Eagle Ford property acquisition and (ii) the absence of accretion of original issue discount attributable to the 10.375% Senior Notes due 2016, or the 2016 Senior Notes, which were redeemed in May 2013. The weighted-average interest rate declined during 2014 compared to 2013 due primarily to the replacement of the 2016 Senior Notes with the 2020 Senior Notes as well as lower interest rates on borrowings under the Revolver.

Loss on Extinguishment of Debt

In 2013, we redeemed all of the 2016 Senior Notes. We paid a total of $330.9 million, including consent payments and accrued interest, and recognized a loss on the extinguishment of debt of $29.2 million. The loss on extinguishment of debt included non-cash charges of $10.0 million attributable to the write-off of unamortized debt issuance costs and the remaining debt discount associated with the 2016 Senior Notes.

Derivatives

The following table summarizes the components of our derivatives income (loss) for the periods presented:

	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013
				Favorable (unfavorable)	
Oil and gas derivatives settled	$ 138,169	$ (7,424)	$ (1,042)	$ (145,593)	$ 6,382
Oil and gas derivative (loss) gain	(66,922)	169,636	(19,810)	236,558	(189,446)
	$ 71,247	$ 162,212	$ (20,852)	$ 90,965	$ (183,064)

2015 vs. 2014. During 2015, we received cash settlements of $137.5 million from crude oil derivatives as compared to making cash payments of $6.2 million during 2014. The crude oil derivative portfolio was "in-the-money," throughout all of 2015 as a result of declining prices compared to the hedge contract prices. Our natural gas hedges expired in 2015 and provided $0.7 million of cash receipts from settlements in 2015 versus requiring cash payments of $1.2 million for settlements during 2014. The derivative gains and losses represent period-end mark-to-market adjustments on unexpired hedge contracts.

2014 vs. 2013. During 2014, we paid cash settlements of $6.2 million from crude oil derivatives compared to $2.6 million during 2013 and we were required to make payments for cash settlements of $1.2 million for natural gas derivatives in 2014 compared to receipts from cash settlements of $1.6 million in 2013.

Other

In 2015, we wrote-off a combined $1.6 million of receivables from various joint interest partners and other parties related to our 2013 Eagle Ford acquisition that we have determined are not collectible as well as approximately $2 million of unrecoverable amounts from prior years, including GPT charges and other revenue deductions, attributable primarily to properties that have been sold. In 2014, we recognized $1.3 million of interest received in connection with an acquisition-related arbitration matter. In 2013, we recognized other income of $0.1 million which was primarily interest.

Income Taxes

	Year Ended December 31,			2015 vs.	2014 vs.
	2015	2014	2013	2014	2013
				Favorable (unfavorable)	
Income tax benefit	$ 5,371	$ 131,678	$ 77,696	$ 126,307	$ (53,982)
Effective tax rate	0.3%	24.3%	35.2%		

2015. We recognized a federal income tax benefit for 2015 at the statutory rate of 35%; however, the federal tax benefit was fully offset by a valuation allowance against our net deferred tax assets. We also provided for a full valuation allowance against our state deferred tax assets. We considered both the positive and negative evidence in determining that it was more likely than not that some portion or all of our deferred tax assets will not be realized, primarily as a result of recent cumulative losses. We also recognized a benefit of $0.7 million attributable to a federal return to provision adjustment and a minimal deferred state income tax expense resulting in a combined effective tax rate of 0.3% for 2015. The significant difference between our combined federal and state statutory rate of 35.7% and our effective tax of 0.3% is due almost entirely to the incremental valuation allowance placed against our deferred tax assets.

2014. Due to the pre-tax operating loss incurred in 2014, we recognized an income tax benefit. Our income tax benefit was reduced by a combined federal and state $62.8 million valuation allowance against our net deferred tax assets. The federal portion of the valuation allowance was $61.1 million which reduced the carrying value of our federal net deferred tax assets to zero. The significant difference between our blended federal and state statutory income tax rate of 35.7% and our effective income tax rate of 24.3% in 2014 was almost entirely attributable to the incremental valuation allowance placed against our deferred tax assets. Absent this valuation allowance, our effective income tax rate would have been 35.6%.

2013. Due to the pre-tax operating loss incurred in 2013, we recognized an income tax benefit. The effective tax rate included a deferred tax asset valuation allowance for state net operating losses.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2015, the material off-balance sheet arrangements and transactions that we have entered into included operating lease arrangements, well drilling commitments, well completion service commitments, firm transportation agreements and letters of credit, all of which are customary in our business. See “Contractual Obligations” summarized below and Note 14 to the Consolidated Financial Statements for more details related to the value of our off-balance sheet arrangements. We did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise had we engaged in such relationships.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2015:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Revolver [1]	$ 170,000	$ —	$ 170,000	$ —	$ —
Senior Notes due 2019 and 2020 [2]	1,075,000	—	—	1,075,000	—
Interest payments on long-term debt [3]	385,972	95,275	181,009	109,688	—
Operating leases [4]	8,818	2,606	4,871	1,341	—
Well drilling and completion commitments [5]	3,984	3,984	—	—	—
Firm transportation commitments [6]	32,649	3,892	7,773	7,763	13,221
Natural gas gathering commitments [7]	5,000	5,000	—	—	—
Crude oil gathering and transportation commitments [8]	123,289	10,328	24,638	24,671	63,652
Asset retirement obligations [9]	60,381	—	—	—	60,381
Drilling carry [10]	10,664	1,900	8,764	—	—
Other commitments [11]	804	459	345	—	—
Total contractual obligations [12]	$ 1,876,561	$ 123,444	$ 397,400	$ 1,218,463	$ 137,254

[1] Assumes that the amount outstanding of $170 million as of December 31, 2015 will remain outstanding until is maturity on 2017. The Revolver has been classified as a current liability on our Consolidated Balance Sheet as described in “Financial Condition – Liquidity” and in Note 9 to the Consolidated Financial Statements.

[2] Upon their maturities in April 2019 and May 2020, the principal amounts of $300 million and $775 million will be due. The 2019 Senior Notes and the 2020 Senior Notes have been classified as current liabilities on our Consolidated Balance Sheet as described in “Financial Condition – Liquidity” and in Note 9 to the Consolidated Financial Statements.

[3] Represents estimated interest payments that will be due under the Revolver, assuming the amount outstanding of $170 million as of December 31, 2015 will remain outstanding until its maturity in 2017, as well as contractual interest payments on the 2019 Senior Notes and the 2020 Senior Notes.

[4] Relates primarily to office and equipment leases.

[5] Represents our remaining commitment for one drilling rig and certain coil tubing services.

[6] Includes $18.6 million of undiscounted payments attributable to a firm transportation obligation for which a fair value of $13.5 million has been recognized on our Consolidated Balance Sheet as of December 31, 2015.

[7] Represents minimum payments for natural gas gathering, compression and gas lift services in South Texas.

[8] Represents minimum payments for gathering and intermediate pipeline transportation services for our crude oil and condensate production in South Texas.

[9] Represents the undiscounted balance payable in periods more than five years in the future for which $2.6 million has been recognized on our Consolidated Balance Sheet as of December 31, 2015. While we could make payments to settle asset retirement obligations during each of the next five years, none are currently required by contract to be made during this time frame.

[10] Represents a commitment for expenditures to develop certain Eagle Ford acreage that was acquired in 2014.

[11] Represents all other significant obligations, including information technology licensing and service agreements, among others.

[12] Does not include accumulated and unpaid preferred stock dividends of $22.8 million as of December 31, 2015.

Critical Accounting Estimates

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting estimates requiring judgment of our management.

Oil and Gas Reserves

Estimates of our oil and gas reserves are the most critical estimate included in our Consolidated Financial Statements. Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties acquired as well as those subject to potential impairments. There are many uncertainties inherent in estimating crude oil, NGL and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the amount and timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

There are several factors which could change the estimates of our oil and gas reserves. Significant rises or declines in commodity product prices as well as changes in our drilling plans could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to the necessary facilities or receiving to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

We assess our proved oil and gas properties for impairment on a geographic basis, generally at the field level, based upon a periodic review of commodity prices and, when available, updated oil and gas reserve data. Generally, we compile updated oil and gas reserve data once during the calendar year and again at year-end on a more formal basis. The assessment is performed by comparing the carrying value of proved properties for each field to the undiscounted estimated future cash flows. Undiscounted estimated future cash flows are based on updated oil and gas reserve data, when available, and include the impact of risk-adjusted probable and possible reserves, future commodity prices, anticipated production and forecasted operating and capital expenditures. Commodity prices are estimated based on five-year NYMEX strip prices, adjusted accordingly for basis differentials and other factors consistent with management's assumptions utilized for internal planning and budgeting purposes. If, based on the assessment, the carrying value of the proved properties exceeds the undiscounted estimated future cash flows, the cost of the proved properties are written down to fair value. In certain circumstances, significant management judgment is applied to consideration of the results of such assessment described above. Accordingly, it is possible that impairment would not be appropriate for certain properties that failed the objective assessment based on consideration of other factors, including the timeliness of reserve assignment, among others. Likewise, impairment may be appropriate for other properties that otherwise passed the objective assessment based on the trending of prices, lease expirations and future development plans.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. Unproved properties whose acquisition costs are insignificant are amortized as a component of exploration expense in the aggregate over the lesser of five years or the average remaining lease term. We assess unproved properties whose acquisition costs are relatively significant, if any, for impairment on a stand-alone basis. As exploration and development work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depreciation and depletion. If exploration activities are unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of any write-downs of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

As of January 1, 2013, we had no unproved properties that were deemed significant as described above. Subsequent to our 2013 Eagle Ford acquisition, our unproved properties in the Eagle Ford were designated as significant and became subject to impairment on a stand-alone basis effective July 1, 2013. Subsequent to that date, we transferred significant amounts representing the cost of unproved leaseholds to proved properties and subjected such costs to depletion. At December 31, 2015, our impairment assessment indicated a significant decrease in the value of the remaining unproved property in Eagle Ford and it was written down to its fair value of approximately $6.9 million.

Depreciation, Depletion and Amortization

We determine depreciation and depletion of oil and gas producing properties by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves. We compute depreciation and amortization of other property and equipment using the straight-line balance method over the estimated useful life of each asset.

Derivative Activities

From time to time, we enter into derivative instruments to mitigate our exposure to crude oil and natural gas price volatility and interest rate fluctuations. The derivative financial instruments, which are placed with financial institutions that we believe are of acceptable credit risk, take the form of collars, swaps and swaptions, among others. All derivative instruments are recognized in our Consolidated Financial Statements at fair value with the changes recorded currently in earnings. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices and rates. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

Deferred Tax Asset Valuation Allowance

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized after consideration of future taxable income and reasonable tax planning strategies. In the event that we were to determine that we would not be able to realize all or a part of our deferred tax assets for which a valuation allowance had not been established, an adjustment to the deferred tax asset will be reflected in income in the period such determination is made. The most significant matter applicable to the realization of our deferred tax assets is attributable to net operating losses in certain states. Estimates of future taxable income inherently reflect a significant degree of uncertainty. During the years ended December 31, 2015 and 2014, we increased the valuation allowance for our deferred tax assets due primarily to our inability to project sufficient future taxable income in certain states.

Share-Based Compensation

We granted PBRSUs to certain executive officers. Vested PBRSUs are payable in cash on the third anniversary of the date of grant based upon the achievement of specified market-based performance metrics with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The number of PBRSUs vested can range from 0% to 200% of the initial grant. The PBRSUs do not have voting rights and do not participate in dividends.

Because the PBRSUs are payable solely in cash, they are considered liability-classified awards and are included in the Accounts payable and accrued expenses or Other liabilities captions, based on their vesting maturities, on our Consolidated Balance Sheets. Compensation cost associated with the PBRSUs is measured at the end of each reporting period based on the fair value derived from a Monte Carlo model and recognized based on the period of time that has elapsed during each of the individual performance periods. The Monte Carlo model is a binomial valuation model that requires significant judgment with respect to certain assumptions, including volatility, dividends and other factors. Due primarily to the sensitivity of certain model assumptions, as well as the inherent variability of modeling market-based performance over future periods, our compensation expense with respect to the PBRSUs can be volatile. For example, mark-to-market valuation of the PBRSUs resulted in a reduction to general and administrative expenses of $0.7 million during 2015 as compared to charges of $4.5 million and $4.1 million for 2014 and 2013, respectively.

Disclosure of the Impact of Recently Issued Accounting Standards to be Adopted in the Future

In February 2016, the FASB issued Accounting Standards Update, or ASU, No. 2016–01, *Leases* ("ASU 2016–01"), which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than 12 months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–01 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. We are evaluating the effect that ASU 2016–01 will have on our Consolidated Financial Statements and related disclosures.

In May 2014, the FASB issued ASU No. 2014–09, *Revenues from Contracts with Customers,* or ASU 2014–09, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective on January 1, 2017. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. We are evaluating the effect that ASU 2014–09 will have on our Consolidated Financial Statements and related disclosures. We have not yet selected a transition method nor have we determined the effect of ASU 2014–09 on our ongoing financial reporting.

Item 7A Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and commodity price risk.

Interest Rate Risk

All of our long-term debt instruments, with the exception of the Revolver, have fixed interest rates. Accordingly, our interest rate risk is attributable to our borrowings under the Revolver, which is subject to variable interest rates. As of December 31, 2015, we had borrowings of $170 million under the Revolver at an interest rate of 4.5%. Assuming a constant borrowing level of $170 million under the Revolver, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in interest expense of approximately $1.7 million on an annual basis.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars, swaps and swaptions) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of oil and natural gas. We have not typically entered into derivative instruments with respect to NGLs, although we may do so in the future.

As of December 31, 2015, we reported a commodity derivative asset of $98.0 million. The contracts associated with this position are with seven counterparties, all of which are investment grade financial institutions, and are substantially concentrated with five of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties. The maximum amount of loss due to credit risk if counterparties to our derivative asset positions fail to perform according to the terms of the contracts would be equal to the fair value of the contracts as of December 31, 2015.

During the year ended December 31, 2015, we reported net commodity derivative income of $71.2 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 6 to our Consolidated Financial Statements for a further description of our price risk management activities.

The following table sets forth our commodity derivative positions as of December 31, 2015:

	Instrument	Average Volume Per Day	Weighted Average Price			Fair Value		
			Floor/Swap		Ceiling	Asset		Liability
Crude Oil:		(barrels)	($/barrel)					
First quarter 2016	Swaps	6,000	$	80.41		$ 22,894	$	—
Second quarter 2016	Swaps	6,000	$	80.41		21,509		—
Third quarter 2016	Swaps	6,000	$	80.41		20,767		—
Fourth quarter 2016	Swaps	6,000	$	80.41		19,937		—

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying commodity prices. This illustration assumes that crude oil prices, natural gas prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

	Change of $10.00 per Barrel of Crude Oil or $1.00 per MMBtu of Natural Gas ($ in millions)	
	Increase	Decrease
Effect on the fair value of crude oil derivatives	$ (21.8)	$ 22.0
Effect on 2016 operating income, excluding crude oil derivatives [1]	$ 22.6	$ (22.6)
Effect on 2016 operating income, excluding natural gas derivatives [1]	$ 3.5	$ (3.5)

[1] Based on a forecast which assumes a one-rig drilling program consistent with the assumptions used to determine our proved reserves as disclosed in Item 2, “Properties – Summary of Oil and Gas Reserves.” Based on the Eleventh Amendment and any subsequent refinancing, these sensitivities could change significantly.

Item 8 Financial Statements and Supplementary Data

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Penn Virginia Corporation and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in note 2 to the consolidated financial statements, the Company has suffered recurring losses from operations and is dependent on obtaining additional financing to continue its planned principal business operations. These factors raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Penn Virginia Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 15, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
March 15, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited Penn Virginia Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Penn Virginia Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Penn Virginia Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Penn Virginia Corporation and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and our report dated March 15, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
March 15, 2016

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31, 2015	2014	2013
Revenues			
Crude oil	$ 220,596	$ 420,286	$ 347,407
Natural gas liquids (NGLs)	16,905	34,552	30,748
Natural gas	25,479	58,044	52,538
Gain (loss) on sales of property and equipment, net	41,335	120,769	(266)
Other, net	983	3,122	1,041
Total revenues	305,298	636,773	431,468
Operating expenses			
Lease operating	42,428	48,298	35,461
Gathering, processing and transportation	23,815	18,294	12,839
Production and ad valorem taxes	16,282	27,990	22,404
General and administrative	43,328	49,005	53,998
Exploration	12,583	17,063	20,994
Depreciation, depletion and amortization	334,479	300,299	245,594
Impairments	1,397,424	791,809	132,224
Total operating expenses	1,870,339	1,252,758	523,514
Operating loss	(1,565,041)	(615,985)	(92,046)
Other income (expense)			
Interest expense	(90,951)	(88,831)	(78,841)
Loss on extinguishment of debt	—	—	(29,174)
Derivatives	71,247	162,212	(20,852)
Other	(3,587)	1,334	147
Loss before income taxes	(1,588,332)	(541,270)	(220,766)
Income tax benefit	5,371	131,678	77,696
Net loss	(1,582,961)	(409,592)	(143,070)
Preferred stock dividends	(22,789)	(17,148)	(6,900)
Induced conversion of preferred stock	—	(4,256)	—
Net loss attributable to common shareholders	$ (1,605,750)	$ (430,996)	$ (149,970)
Net loss per share:			
Basic	$ (21.81)	$ (6.26)	$ (2.41)
Diluted	$ (21.81)	$ (6.26)	$ (2.41)
Weighted average shares outstanding – basic	73,639	68,887	62,335
Weighted average shares outstanding – diluted	73,639	68,887	62,335

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31,		
	2015	2014	2013
Net loss	$ (1,582,961)	$ (409,592)	$ (143,070)
Other comprehensive income (loss):			
Change in pension and postretirement obligations, net of tax of $93 in 2015, $(10) in 2014 and $673 in 2013	173	(18)	1,249
	173	(18)	1,249
Comprehensive loss	$ (1,582,788)	$ (409,610)	$ (141,821)

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	As of December 31,	
	2015	**2014**
Assets		
Current assets		
Cash and cash equivalents	$ 11,955	$ 6,252
Accounts receivable, net of allowance for doubtful accounts	47,965	189,627
Derivative assets	97,956	128,981
Other current assets	7,104	10,114
Total current assets	164,980	334,974
Property and equipment, net (successful efforts method)	344,395	1,825,098
Derivative assets	—	35,897
Other assets	8,350	5,841
Total assets	$ 517,725	$ 2,201,810
Liabilities and Shareholders' Equity (Deficit)		
Current liabilities		
Accounts payable and accrued liabilities	$ 103,525	$ 312,227
Current portion of long-term debt	1,224,383	—
Total current liabilities	1,327,908	312,227
Other liabilities	104,938	123,886
Deferred income taxes	—	4,451
Long-term debt	—	1,085,429
Commitments and contingencies (Note 14)		
Shareholders' equity (deficit):		
Preferred stock of $100 par value – 100,000 shares authorized; Series A – 3,915 and 7,945 shares issued as of December 31, 2015 and December 31, 2014, respectively, and Series B – 27,551 and 32,500 shares issued as of December 31, 2015 and December 31, 2014, respectively, each with a redemption value of $10,000 per share	3,146	4,044
Common stock of $0.01 par value – 228,000,000 shares authorized; 81,252,676 and 71,568,936 shares issued as of December 31, 2015 and December 31, 2014, respectively	628	529
Paid-in capital	1,211,088	1,206,305
Accumulated deficit	(2,130,271)	(535,176)
Deferred compensation obligation	3,440	3,211
Accumulated other comprehensive income	422	249
Treasury stock – 455,689 and 262,070 shares of common stock, at cost, as of December 31, 2015 and December 31, 2014, respectively	(3,574)	(3,345)
Total shareholders' equity (deficit)	(915,121)	675,817
Total liabilities and shareholders' equity (deficit)	$ 517,725	$ 2,201,810

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net loss	$ (1,582,961)	$ (409,592)	$ (143,070)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Loss on extinguishment of debt	—	—	29,174
Depreciation, depletion and amortization	334,479	300,299	245,594
Impairments	1,397,424	791,809	132,224
Accretion of firm transportation obligation	942	1,301	1,674
Derivative contracts:			
Net (gains) losses	(71,247)	(162,212)	20,852
Cash settlements, net	138,169	(7,424)	(1,042)
Deferred income tax benefit	(4,712)	(135,227)	(77,696)
(Gain) loss on sales of assets, net	(41,335)	(120,769)	266
Non-cash exploration expense	5,759	10,346	17,451
Non-cash interest expense	4,749	4,197	3,844
Share-based compensation (equity-classified)	4,540	3,627	5,781
Other, net	13	94	297
Changes in operating assets and liabilities:			
Accounts receivable, net	137,854	(20,169)	(105,023)
Accounts payable and accrued expenses	(152,553)	27,362	129,670
Other assets and liabilities	(1,818)	(918)	1,516
Net cash provided by operating activities	169,303	282,724	261,512
Cash flows from investing activities			
Capital expenditures – property and equipment	(364,844)	(774,139)	(504,203)
Acquisition, net	—	—	(358,239)
Receipts (payments) to settle working capital adjustments assumed in acquisition, net	—	33,712	(22,455)
Proceeds from sales of assets, net	85,189	313,933	(54)
Net cash used in investing activities	(279,655)	(426,494)	(884,951)
Cash flows from financing activities			
Proceeds from revolving credit facility borrowings	233,000	412,000	297,000
Repayment of revolving credit facility borrowings	(98,000)	(583,000)	(91,000)
Proceeds from the issuance of preferred stock, net	—	313,330	—
Payments to induce conversion of preferred stock	—	(4,256)	—
Proceeds from the issuance of senior notes	—	—	775,000
Retirement of senior notes	—	—	(319,090)
Debt issuance costs paid	(744)	(151)	(25,634)
Dividends paid on preferred stock	(18,201)	(12,803)	(6,862)
Other, net	—	1,428	(151)
Net cash provided by financing activities	116,055	126,548	629,263
Net increase (decrease) in cash and cash equivalents	5,703	(17,222)	5,824
Cash and cash equivalents - beginning of period	6,252	23,474	17,650
Cash and cash equivalents - end of period	$ 11,955	$ 6,252	$ 23,474
Supplemental disclosures:			
Cash paid for interest (net of amounts capitalized)	$ 86,226	$ 84,797	$ 65,107
Cash paid for income taxes (net of refunds received)	$ (714)	$ 3,612	$ —
Non-cash investing and financing activities:			
Changes in accrued liabilities related to capital expenditures	$ (55,660)	$ 24,715	$ 6,356
Other assets acquired related to acquisition	$ —	$ —	$ 99,213
Other liabilities assumed related to acquisition	$ —	$ —	$ 96,271
Common stock transferred as consideration for acquisition	$ —	$ —	$ 42,300

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Shares Outstanding	Preferred Stock	Common Stock	Paid-in Capital	Retained Earnings (Accumulated Deficit)	Deferred Compensation Obligation	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders' Equity
Balance as of December 31, 2012	55,117	$ 1,150	$ 364	$ 849,046	$ 45,790	$ 3,111	$ (982)	$ (3,363)	$ 895,116
Net loss	—	—	—	—	(143,070)	—	—	—	(143,070)
Issuance of common stock	10,000		100	42,041	—	—	—	—	42,141
Dividends declared on preferred stock ($600.00 per preferred share)	—	—	—	—	(6,900)	—	—	—	(6,900)
Share-based compensation	78		1	5,780	—	—	—	—	5,781
Deferred compensation	31	—	—	(679)	—	(319)	—	321	(677)
Exercise of stock options	3	—	—	16	—	—	—	—	16
Restricted stock unit vesting	78		1	(252)	—	—	—	—	(251)
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	1,249	—	1,249
Other	—	—	—	(4,601)	—	—	—	—	(4,601)
Balance as of December 31, 2013	65,307	1,150	466	891,351	(104,180)	2,792	267	(3,042)	788,804
Net loss	—	—	—	—	(409,592)	—	—	—	(409,592)
Issuance of preferred stock	—	3,250		310,080	—	—	—	—	313,330
Conversion of preferred stock	5,926	(356)	59	297	—	—	—	—	—
Payments to induce conversion of preferred stock	—	—	—	—	(4,256)	—	—	—	(4,256)
Dividends declared on preferred stock ($600.00 and $348.33 per Series A and Series B preferred share, respectively)	—	—	—	—	(17,148)	—	—	—	(17,148)
Share-based compensation	15	—	1	3,626	—	—	—	—	3,627
Deferred compensation	—	—	—	—	—	419	—	(303)	116
Exercise of stock options	257	—	3	1,425	—	—	—	—	1,428
Restricted stock unit vesting	64	—	—	(474)	—	—	—	—	(474)
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	(18)	—	(18)
Balance as of December 31, 2014	71,569	4,044	529	1,206,305	(535,176)	3,211	249	(3,345)	675,817
Net loss	—	—	—	—	(1,582,961)	—	—	—	(1,582,961)
Conversion of preferred stock	9,414	(898)	94	804	—	—	—	—	—
Dividends declared on preferred stock ($300.00 and $300.00 per Series A and Series B preferred share, respectively)	—	—	—	—	(12,134)	—	—	—	(12,134)
Share-based compensation	195	—	4	4,536	—	—	—	—	4,540
Deferred compensation	2	—	—	—	—	229	—	(229)	—
Restricted stock unit vesting	73	—	1	(557)	—	—	—	—	(556)
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	173	—	173
Balance as of December 31, 2015	81,253	$ 3,146	$ 628	$ 1,211,088	$ (2,130,271)	$ 3,440	$ 422	$ (3,574)	$ (915,121)

See accompanying notes to consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation (together with its consolidated subsidiaries unless the context otherwise requires, "Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company engaged in the onshore exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist primarily of operating our producing wells in the Eagle Ford Shale in South Texas. Our operations are substantially concentrated with approximately 90 percent of our production and over 90 percent of our revenues and capital expenditures being attributable to this region. We also have less significant operations in Oklahoma, primarily in the Granite Wash.

2. Basis of Presentation

These Consolidated Financial Statements have been prepared on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities and other commitments in the normal course of business. Our primary sources of liquidity have historically included cash from operating activities, borrowings under our revolving credit agreement (the "Revolver"), proceeds from the sales of assets and, from time to time, proceeds from capital market transactions, including the offering of debt and equity securities. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for our crude oil, NGL and natural gas products, as well as variations in our production. Due primarily to the substantial decline in commodity prices over the last twelve months, our liquidity has been adversely impacted. We have incurred net losses in each of the three years ending December 31, 2015, and reported a net loss attributable to common shareholders of $(1.6) billion for the year ended December 31, 2015.

Further, based on our current operating forecast and capital structure, we do not believe we will be able to comply with all of the financial covenants under the Revolver during the next twelve months. We are also dependent on restructuring our debt or obtaining additional debt and/or equity financing to continue our planned principal business operations. These factors raise substantial doubt about our ability to continue as a "going concern."

Under the Revolver, we are required to deliver audited, consolidated financial statements without a "going concern" or like qualification or exception. The audit report prepared by our auditors with respect to the financial statements in this Annual Report on Form 10-K includes an explanatory paragraph expressing substantial doubt as to our ability to continue as a "going concern." Therefore, we are in default under the Revolver. Pursuant to an amendment to the Revolver (see Note 9), we have received an agreement from our lenders that such default, together with certain other defaults, will not become events of default until April 12, 2016 (which can be further extended until May 10, 2016 if certain conditions have been satisfied).

As of December 31, 2015, the total outstanding principal amount of our debt obligations was $1.2 billion. We are continuing to actively explore and evaluate various strategic alternatives to reduce the level of our long-term debt and lower our future cash interest obligations. In January 2016, we retained Kirkland & Ellis LLP ("K&E") and Jefferies LLC ("Jefferies") to provide strategic advice generally and to act as our advisors in that regard. The timing and outcome of these efforts is highly uncertain. One or more of these alternatives could potentially be consummated without the consent of any one or more of our current security holders and, if consummated, could be dilutive to the holders of our outstanding equity securities and adversely affect the trading prices and values of our current debt and equity securities or if we were to seek protection under the bankruptcy laws, could cause the shares of our common stock to be canceled, with limited recovery, if any. We are actively working to address these matters; however, there can be no assurance that our efforts will be successful on acceptable terms or at all. The Consolidated Financial Statements do not include any adjustments that may result from the outcome of this uncertainty.

3. Summary of Significant Accounting Policies

Principles of Consolidation

Our Consolidated Financial Statements include the accounts of Penn Virginia and all of its subsidiaries. Intercompany balances and transactions have been eliminated.

Use of Estimates

Preparation of our Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in our Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Such estimates include certain asset and liability valuations as further described in these Notes. Actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Derivative Instruments

From time to time, we utilize derivative instruments to mitigate our financial exposure to commodity price and interest rate volatility. The derivative instruments, which are placed with financial institutions that we believe are of acceptable credit risk, take the form of collars, swaps and swaptions. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

All derivative instruments are recognized in our Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. Our derivative instruments are not formally designated as hedges. We recognize changes in fair value in earnings currently as a component of the Derivatives caption on our Consolidated Statements of Operations. We have experienced and could continue to experience significant changes in the amount of derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts, which fluctuate with changes in crude oil and natural gas prices and interest rates.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to the necessary facilities or receiving such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

Depreciation, depletion and amortization ("DD&A") of proved producing properties is computed using the units-of-production method. Natural gas is converted to a liquids equivalent on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of liquids. Historically, we have adjusted our depletion rate throughout the year as new data becomes available and in the fourth quarter based on our year-end reserve report.

Other Property and Equipment

Other property and equipment consists primarily of gathering systems and related support equipment. Property and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are charged to expense as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized.

We compute depreciation and amortization of property and equipment using the straight-line balance method over the estimated useful life of each asset as follows: Gathering systems – fifteen to twenty years and Other property and equipment – three to twenty years.

Impairment of Long-Lived and Other Assets

We review assets for impairment when events or circumstances indicate a possible decline in the recoverability of the carrying value of such property. If the carrying value of the asset is determined to be impaired, we reduce the asset to its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and could include estimates of future production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, intent to develop properties and a risk-adjusted discount rate.

We review oil and gas properties for impairment periodically when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. Performing the impairment evaluations requires use of judgments and estimates since the results are dependent on future events. Such events include estimates of proved and unproved reserves, future commodity prices, the timing of future production, capital expenditures and intent to develop properties, among others. We cannot predict whether impairment charges will be required in the future.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. Unproved properties whose acquisition costs are insignificant to total oil and gas properties are amortized in the aggregate over the lesser of five years or the average remaining lease term and the amortization is charged to exploration expense. We assess unproved properties whose acquisition costs are relatively significant, if any, for impairment on a stand-alone basis. As exploration work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of any write-downs of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. Associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our AROs relate to the plugging and abandonment of oil and gas wells and the associated asset is recorded as a component of oil and gas properties. After recording these amounts, the ARO is accreted to its future estimated value, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion of the ARO and the depreciation of the related long-lived assets are included in the DD&A expense caption on our Consolidated Statements of Operations.

Income Taxes

We recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Using this method, deferred tax assets and liabilities are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates. In assessing our deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is assessed at each reporting period and is dependent upon the generation of future taxable income and our ability to utilize tax credits and operating loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies. We recognize interest attributable to income taxes, to the extent they arise, as a component of interest expense and penalties as a component of income tax expense.

We are subject to ongoing tax examinations in numerous domestic jurisdictions. Accordingly, we may record incremental tax expense based upon the more-likely-than-not outcomes of uncertain tax positions. In addition, when applicable, we adjust the previously recorded tax expense to reflect examination results when the position is effectively settled. Our ongoing assessments of the more-likely-than-not outcomes of the examinations and related tax positions require judgment and can increase or decrease our effective tax rate, as well as impact our operating results. The specific timing of when the resolution of each tax position will be reached is uncertain.

Revenue Recognition

We record revenues associated with sales of crude oil, NGLs and natural gas when title passes to the customer. We recognize natural gas sales revenues from properties in which we have an interest with other producers on the basis of our net revenue interest ("entitlement" method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of natural gas production. We treat any amount received in excess of our share as a liability. If we take less than we are entitled to take, we record the under-delivery as a receivable. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production, particularly from properties that are operated by our partners. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

Share-Based Compensation

Our stock compensation plans permit the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. We measure the cost of employee services received in exchange for an award of equity-classified instruments based on the grant-date fair value of the award. Compensation cost associated with the liability-classified awards is measured at the end of each reporting period and recognized based on the period of time that has elapsed during the applicable performance period.

Recent Accounting Standards

Effective January 2015, we adopted the provisions of Accounting Standards Update ("ASU") No. 2015–017, *Balance Sheet Classification of Deferred Taxes* ("ASU 2015–17"), on a retrospective basis. ASU 2015–17 requires the offsetting of all deferred income tax assets and liabilities (and valuation allowances) for each taxpaying jurisdiction within each tax-paying component and presentation of the net deferred income tax as a single noncurrent amount. In connection with the retrospective application of ASU 2015-17, deferred income taxes previously classified as a component of Current assets were reclassified to noncurrent liabilities as of December 31, 2014 (see Note 10).

Effective January 2015, we also adopted the provisions of ASU No. 2015–03, *Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015–03") on a retrospective basis. ASU 2015–03 requires that debt issuance costs be presented as a direct reduction to the face amount of the underlying debt instruments to which they are attributable. Accordingly, we have presented the debt issuance costs, net of amortization, associated with our outstanding senior notes, which were formerly presented as a component of Other assets, as a reduction to Long-term debt (see Notes 9 and 12) for all periods presented. Issuance costs associated with the Revolver continue to be presented, net of amortization, as a component of Other assets (see Note 12) as clarified by ASU 2015–15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements–Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update)* ("ASU 2015–15").

In February 2016, the FASB issued ASU No. 2016–01, *Leases* ("ASU 2016–01"), which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than 12 months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–01 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. We are evaluating the effect that ASU 2016–01 will have on our Consolidated Financial Statements and related disclosures.

In May 2014, the FASB issued ASU No. 2014–09, *Revenues from Contracts with Customers* ("ASU 2014–09"), which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective on January 1, 2017. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. We are evaluating the effect that ASU 2014–09 will have on our Consolidated Financial Statements and related disclosures. We have not yet selected a transition method nor have we determined the effect of ASU 2014–09 on our ongoing financial reporting.

Reclassifications

Certain amounts for the 2014 and 2013 periods have been reclassified to conform to the current year presentation. These reclassifications have no impact on our previously reported results of operations, balance sheets or cash flows.

Subsequent Events

Management has evaluated all activities of the Company, through the date upon which our Consolidated Financial Statements were issued, and concluded that, except for an amendment to the Revolver as disclosed in Note 9, no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes to Consolidated Financial Statements.

4. Acquisitions and Divestitures

Acquisitions

Undeveloped Eagle Ford Acreage

In August 2014, we acquired undeveloped acreage in the Eagle Ford in Lavaca County, Texas for a purchase price of $45.6 million, of which $34.9 million was paid at closing and the balance of $10.7 million will be paid over three years as a drilling carry.

Eagle Ford Acquisition

On April 24, 2013 (the "Acquisition Date"), we acquired producing properties and undeveloped leasehold interests in the Eagle Ford (the "Eagle Ford Acquisition"). The Eagle Ford Acquisition was originally valued at $401 million with an effective date of January 1, 2013 (the "Effective Date"). On the Acquisition Date, we paid approximately $380 million in cash, including approximately $19 million of initial purchase price adjustments related to the period from the Effective Date to the closing, and issued to the seller 10 million shares of our common stock with a fair value of $4.23 per share. Shortly after the closing, certain of our joint interest partners exercised preferential rights related to the Eagle Ford Acquisition. We received approximately $21 million from the exercise of these rights, which was recorded as a decrease to the purchase price for the Eagle Ford Acquisition. Subsequent to the Acquisition Date and through December 31, 2013, we paid a total of $22.5 million, net, to settle working capital adjustments assumed in the Eagle Ford Acquisition. We were involved in an arbitration with the seller related to disputes we had regarding contractual adjustments to the purchase price for the Eagle Ford Acquisition and suspense funds that we believed the seller was obligated to transfer to us. The arbitration was settled in 2014 based on the arbitrator's determination and the seller paid us a total of $35.1 million, including purchase price adjustments, revenue suspense funds due to partners and royalty owners and interest ($1.3 million) on the funds since the Acquisition Date.

We incurred $2.6 million of transaction costs associated with the Eagle Ford Acquisition, including advisory, legal, due diligence and other professional fees in 2013. We incurred $0.6 million of professional fees associated with the arbitration proceedings in 2014. These costs, as well as fees that we paid to the seller for certain transition services, have been included in the General and administrative caption on our Consolidated Statements of Operations.

We accounted for the Eagle Ford Acquisition by applying the acquisition method of accounting as of the Acquisition Date. The following table represents the fair values assigned to the net assets acquired as of the Acquisition Date and the consideration paid:

Assets		
Oil and gas properties – proved	$	267,688
Oil and gas properties – unproved		119,709
Accounts receivable, net		107,345
Other current assets		2,068
		496,810
Liabilities		
Accounts payable and accrued expenses		94,771
Other liabilities		1,500
		96,271
Net assets acquired	$	400,539
Cash, net of amounts received for preferential rights	$	358,239
Fair value of the Shares issued to seller		42,300
Consideration paid	$	400,539

The fair values of the acquired net assets were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to valuation of oil and gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future cash flows and (v) a market-based weighted-average cost of capital. Because many of these inputs are not observable, we have classified the initial fair value estimates as Level 3 inputs as that term is defined in U.S. GAAP.

The results of operations attributable to the Eagle Ford Acquisition have been included in our Consolidated Financial Statements from the Acquisition Date. The following table presents unaudited summary pro forma financial information for the year ended December 31, 2013 assuming the Eagle Ford Acquisition and the related financing occurred as of January 1, 2012.

The pro forma financial information does not purport to represent what our results of operations would have been if the Eagle Ford Acquisition had occurred as of this date or the results of operations for any future periods.

Total revenues	$	457,811
Net loss attributable to common shareholders	$	(148,272)
Loss per share – basic and diluted	$	(2.27)

Divestitures

South Texas Properties

In October 2015, we sold certain non-core Eagle Ford properties for $12.5 million net of transaction costs and customary closing adjustments. We recognized a loss of $9.5 million on this transaction.

East Texas Properties

In August 2015, we sold our Cotton Valley and Haynesville Shale assets in East Texas and received cash proceeds of approximately $73 million, net of transaction costs and customary closing adjustments. The effective date of the sale was May 1, 2015 and we recognized a gain of approximately $43 million. The carrying value of the net assets disposed in this transaction was $29.5 million, including oil and gas properties and other assets of $33.3 million, net of related asset retirement obligations (“AROs”) of $3.8 million. The net pre-tax operating income (loss), excluding the gain on sale and impairment charges, attributable to the East Texas assets was $1.3 million, $(27.5) million and $(22.2) million for the years ended December 31, 2015, 2014 and 2013, respectively. The net proceeds from this transaction were used to pay down a portion of our outstanding borrowings under the Revolver.

Oil Gathering System Construction Rights

In July 2014, we sold the rights to construct a crude oil gathering and intermediate transportation system in South Texas to Republic Midstream, LLC (“Republic”) for proceeds of $147.1 million, net of transaction costs. Concurrent with the sale, we entered into long-term agreements with Republic to provide us gathering and intermediate transportation services for a substantial portion of our future South Texas crude oil and condensate production. We realized a gain of $147.1 million, of which $63.0 million was recognized upon the closing of the transaction and the remaining $84.1 million was deferred and will be recognized over a twenty-five year period beginning after the system has been constructed and is operational, which is currently expected in the first half of 2016. In September 2015, the gathering agreement with Republic was amended to reduce the number of wells initially required to be connected to the pipeline system, provide for alternative transportation in areas that will not be served by the pipeline and also reduce the gathering fees. As a result of the amendment, we recognized $8.4 million of deferred gain in September 2015. As of December 31, 2015, $2.2 million of the deferred gain is included as a component of Accounts payable and accrued expenses and $73.6 million, representing the noncurrent portion, is included as a component of Other liabilities on our Consolidated Balance Sheets.

Mississippi Properties

In July 2014, we sold our Selma Chalk assets in Mississippi for proceeds of $67.9 million, net of transaction costs and customary closing adjustments. An impairment charge of $117.9 million was recognized in the second quarter of 2014 with respect to these assets.

Natural Gas Gathering and Gas Lift Assets

In January 2014, we sold our natural gas gathering and gas lift assets in South Texas to American Midstream Partners, LP (“AMID”) for proceeds of approximately $96 million, net of transaction costs. Concurrent with the sale, we entered into a long-term agreement with AMID to provide us natural gas gathering, compression and gas lift services for a substantial portion of our current and future South Texas natural gas production. We realized a gain of $67.3 million, of which $56.7 million was recognized upon the closing of the transaction and the remainder was deferred and is being amortized over a twenty-five year period. We amortized $0.4 million of the deferred gain in both 2015 and 2014. As of December 31, 2015, $0.4 million of the remaining deferred gain is included as a component of Accounts payable and accrued expenses and $9.4 million, representing the noncurrent portion, is included as a component of Other liabilities on our Consolidated Balance Sheets.

Other Assets

During 2014, we also received net proceeds of $2.9 million and recognized net gains of $0.2 million from the sale of various non-core oil and gas properties and tubular inventory and well materials. During 2013, payments of post-closing adjustments attributable to sales of properties from prior years were partially offset by net proceeds from sales of individually insignificant oil and gas properties and tubular inventory and well materials, resulting in net payments of $0.1 million and a recognized loss on the sale of assets of $0.3 million.

5. Accounts Receivable and Major Customers

The following table summarizes our accounts receivable by type as of the dates presented:

	As of December 31, 2015	As of December 31, 2014
Customers	$ 23,481	$ 62,650
Joint interest partners	18,381	120,708
Other	7,658	6,549
	49,520	189,907
Less: Allowance for doubtful accounts	(1,555)	(280)
	$ 47,965	$ 189,627

For the year ended December 31, 2015, three customers accounted for $168.9 million, or approximately 64% of our consolidated product revenues. The revenues generated from these customers during 2015 were $74.5 million, $63.5 million and $30.9 million or 28%, 24%, and 12% of the consolidated total, respectively. As of December 31, 2015, $21.1 million, or approximately 90% of our consolidated accounts receivable from customers was related to these customers. For the year ended December 31, 2014, three customers accounted for $258.7 million, or approximately 50% of our consolidated product revenues. The revenues generated from these customers during 2014 were $113.6 million, $80.1 million and $65.0 million, or approximately 22%, 16% and 12% of the consolidated total, respectively. As of December 31, 2014, $36.1 million, or approximately 58% of our consolidated accounts receivable from customers was related to these customers. No significant uncertainties exist related to the collectability of amounts owed to us by any of these customers.

6. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to crude oil and natural gas price volatility. Our derivative instruments are not formally designated as hedges.

Commodity Derivatives

We utilize collars and swaps, which are placed with financial institutions that we believe are acceptable credit risks, to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

The counterparty to a collar or swap contract is required to make a payment to us if the settlement price for any settlement period is below the floor or swap price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling or swap price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of the end of the reporting period. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position.

The following table sets forth our commodity derivative positions as of December 31, 2015:

	Instrument	Average Volume Per Day	Weighted Average Price Floor/Swap	Weighted Average Price Ceiling	Fair Value Asset	Fair Value Liability
Crude Oil:		**(barrels)**	**($/barrel)**			
First quarter 2016	Swaps	6,000	$ 80.41		$ 22,894	$ —
Second quarter 2016	Swaps	6,000	$ 80.41		21,509	—
Third quarter 2016	Swaps	6,000	$ 80.41		20,767	—
Fourth quarter 2016	Swaps	6,000	$ 80.41		19,937	—
Settlements to be received in subsequent period					12,849	—

Financial Statement Impact of Derivatives

The impact of our derivatives activities on income is included in the Derivatives caption on our Consolidated Statements of Operations. The following table summarizes the effects of our derivative activities for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Cash settlements and gains (losses):			
Cash received (paid) for:			
Commodity contract settlements	$ 138,169	$ (7,424)	$ (1,042)
Gains (losses) attributable to:			
Commodity contracts	(66,922)	169,636	(19,810)
	$ 71,247	$ 162,212	$ (20,852)

The effects of derivative gains and (losses) and cash settlements of our commodity derivatives are reported as adjustments to reconcile net income (loss) to net cash provided by operating activities. These items are recorded in the Derivative contracts section of our Consolidated Statements of Cash Flows under the Net losses (gains) and Cash settlements, net captions.

The following table summarizes the fair value of our derivative instruments, as well as the locations of these instruments, on our Consolidated Balance Sheets as of the dates presented:

		Fair Values as of			
		December 31, 2015		December 31, 2014	
Type	**Balance Sheet Location**	**Derivative Assets**	**Derivative Liabilities**	**Derivative Assets**	**Derivative Liabilities**
Commodity contracts	Derivative assets/liabilities – current	$ 97,956	$ —	$ 128,981	$ —
Commodity contracts	Derivative assets/liabilities – noncurrent	—	—	35,897	—
		$ 97,956	$ —	$ 164,878	$ —

As of December 31, 2015, we reported a commodity derivative asset of $98.0 million. The contracts associated with this position are with seven counterparties, all of which are investment grade financial institutions, and are substantially concentrated with five of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We have neither paid to nor received from our counterparties any cash collateral in connection with our derivative positions. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

7. Property and Equipment

The following table summarizes our property and equipment as of the dates presented:

	As of December 31,	
	2015	2014
Oil and gas properties:		
Proved	$ 2,678,415	$ 3,390,482
Unproved [1]	6,881	125,676
Total oil and gas properties	2,685,296	3,516,158
Other property and equipment	31,365	75,073
Total property and equipment	2,716,661	3,591,231
Accumulated depreciation, depletion and amortization [1]	(2,372,266)	(1,766,133)
	$ 344,395	$ 1,825,098

[1] See Note 17 for information regarding impairments to our property and equipment.

During 2013, we reclassified to wells, equipment and facilities, $4.4 million of capitalized exploratory drilling costs for one well that was pending determination of proved reserves as of December 31, 2012.

8. Asset Retirement Obligations

The following table reconciles our AROs as of the dates presented, which are included in the Other liabilities caption on our Consolidated Balance Sheets:

	As of December 31,	
	2015	2014
Balance at beginning of year	$ 5,890	$ 6,437
Changes in estimates	172	112
Liabilities incurred	110	238
Liabilities settled	—	(92)
Sale of properties	(3,932)	(1,224)
Accretion expense	381	419
Balance at end of year	$ 2,621	$ 5,890

9. Long-Term Debt

The following table summarizes our long-term debt as of the dates presented:

	As of December 31,			
	2015		2014	
	Principal	Unamortized Issuance Costs	Principal	Unamortized Issuance Costs
Revolving credit facility [1]	$ 170,000		$ 35,000	
Senior notes due 2019	300,000	3,295	300,000	4,131
Senior notes due 2020	775,000	17,322	775,000	20,440
Totals	$ 1,245,000	$ 20,617	$ 1,110,000	$ 24,571
Less: Unamortized issuance costs	(20,617)		(24,571)	
Less: Current portion	(1,224,383)		—	
Long-term debt, net of unamortized issuance costs	$ —		$ 1,085,429	

[1] Issuance costs attributable to the Revolver, which represent costs attributable to the access to credit over the Revolver's contractual term, are presented as a component of Other assets (see Note 12) in accordance with ASU 2015-15.

Revolving Credit Facility

In January 2016, the Revolver was amended to (i) allow us to convert to or continue LIBOR loans without having to make a solvency representation and (ii) increase our mortgage requirement from 80 percent to100 percent (subject to certain exceptions) of our proved reserves. In November 2015, in connection with the semi-annual redetermination, our lenders decreased their aggregate total commitment and borrowing base under the Revolver to $275 million due primarily to depressed commodity prices and our reduced capital program.

On March 15, 2016, we entered into the Eleventh Amendment (the “Eleventh Amendment”) to the Revolver. The Eleventh Amendment provides (i) for an extension before certain events of default under the Revolver will occur, (ii) for a reduction in commitments to $171.8 million and (iii) that the borrowing base under the Revolver is not subject to scheduled redetermination until May 15, 2016. Specifically, the extension period with respect to events of default is through 12:01 am on April 12, 2016, which can be further extended through 12:01 am on May 10, 2016, if certain conditions have been satisfied. The extension period can be terminated early upon certain triggering events. The key conditions to the first extension (April 12, 2016) and entry to the Eleventh Amendment are: (i) termination of certain hedge agreements and application of the proceeds against the loans (which will result in a further reduction in our lenders’ commitments), (ii) entry into control agreements over deposit accounts, subject to customary exceptions, (iii) payment of advisor fees, and (iv) agreement to certain changes to the Revolver, including increasing the interest rate by 1.00%, tightening certain restrictive covenants and agreeing that monthly hedge settlements will be applied against the loans. The key conditions to the second extension (May 10, 2016) are: (i) termination of certain additional hedges and application of the proceeds against the loans (which will result in a further reduction in our lenders’ commitments) and (ii) no notification by the representative of the ad hoc committee of unsecured noteholders that they do not support such extension.

The Revolver also includes a $20 million sublimit for the issuance of letters of credit. Pursuant to the Eleventh Amendment, our sublimit for the issuance of letters of credit was reduced to $1.8 million plus additional amounts specifically described in the Eleventh Amendment. The Revolver is governed by a borrowing base calculation, which is redetermined at least semi-annually, and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base.

Pursuant to the Eleventh Amendment, the commitments under the Revolver were reduced to $171.8 million, which is equal to our currently outstanding loans ($170 million) and issued letters of credit ($1.8 million) under the Revolver. Because we do not have any unused commitment capacity, we will not be able to draw on the Revolver to pay our second quarter interest payments on our senior notes or for any other purpose. Moreover, our lenders may in the future exercise their right to redetermine our $275 million borrowing base under the Revolver. Pursuant to the Eleventh Amendment, any such redetermination will not occur until after May 15, 2016. If our borrowing base is redetermined below the amount of our outstanding borrowings, a deficiency will result, and any deficiency must be repaid within 60 days.

Revolver borrowings may be used for general purposes including working capital, capital expenditures and acquisitions. The Revolver matures in September 2017. We had letters of credit of $1.8 million outstanding as of December 31, 2015. Due to our inability to make solvency representations, we were unable to draw on the Revolver as of December 31, 2015.

Borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from the London Interbank Offered Rate, as adjusted for statutory reserve requirements for Eurocurrency liabilities (“Adjusted LIBOR”), plus an applicable margin (ranging from 1.500% to 2.500%) or (ii) the greater of (a) the prime rate, (b) the federal funds effective rate plus 0.5% or (c) the one-month Adjusted LIBOR plus 1.0% (clauses (a), (b) and (c) (the “Base Rate”)), and, in each case, plus an applicable margin (ranging from 0.500% to 1.500%). Pursuant to the Eleventh Amendment, the applicable margin for Borrowings bearing interest at a rate derived from (a) LIBOR was increased 1.00% (to a range of 2.500% to 3.500%) and (b) the Base Rate was increased by 1.00% (to a range of 1.500% to 2.500%). The applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity. As of December 31, 2015, the actual interest rate on the outstanding borrowings under the Revolver was 4.5000% which is derived from a Prime rate of 3.5000% plus an applicable margin of 1.00%. The applicable interest rate was re-set on January 12, 2016 to a one-month LIBOR-based rate of 2.4375% (Adjusted LIBOR rate of 0.4375% plus an applicable margin of 2.0%). Commitment fees are charged at 0.375% to 0.500% on the undrawn portion of the Revolver depending on our ratio of outstanding borrowings to the available Revolver capacity. As of December 31, 2015, commitment fees were charged at a rate of 0.375%.

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries (the “Guarantor Subsidiaries”). The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of the equity interests in the Guarantor Subsidiaries.

The Revolver includes current ratio, leverage ratio and credit exposure financial covenants. Under the current ratio covenant, the ratio of current assets to current liabilities as of the last day of any fiscal quarter may not be less than 1.0 to 1.0. Current assets and current liabilities attributable to derivative instruments are excluded. In addition, current assets include the amount of any unused commitment under the Revolver. Under the leverage ratio covenant, the ratio of total debt to EBITDAX, for any four consecutive quarters may not exceed 4.75 to 1.0 through March 31, 2016; 5.25 to 1.0 through June 30, 2016; 5.50 to 1.0 through December 31, 2016; 4.50 to 1.0 through March 31, 2017; and 4.0 to 1.0 through maturity in September 2017. Furthermore, we are precluded from the payment of cash dividends on our outstanding convertible preferred stock if the leverage ratio for the preceding four quarters exceeds 5.0 to 1.0. Pursuant to the Eleventh Amendment, we are precluded from making dividends on our outstanding convertible preferred and common stock. Under the credit exposure covenant, the ratio of credit exposure to EBITDAX, for any four consecutive quarters ending on or prior to March 31, 2017 may not exceed 2.75 to 1.0. Credit exposure consists of all outstanding borrowings under the Revolver, including any outstanding letters of credit.

As of December 31, 2015 and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of these covenants except the current ratio covenant under the Revolver. Due primarily to substantial doubt with respect to our ability to continue as a going concern, our registered independent public accountants have expressed an opinion with a going concern explanatory paragraph on our consolidated audited financial statements. A going concern explanatory paragraph represents a violation of one of our non-financial affirmative covenants under the Revolver, which is characterized as a default, thereby making the outstanding borrowings under the Revolver subject to acceleration. These defaults are subject to the extension provided by the Eleventh Amendment, as described above. Due to various cross-default provisions under the indentures governing our senior notes, our senior notes are also classified as current liabilities as of December 31, 2015.

2019 Senior Notes

Our 7.25% Senior Notes due 2019 (the “2019 Senior Notes”), which were issued at par in April 2011, bear interest at an annual rate of 7.25% which is payable on April 15 and October 15 of each year. We may redeem all or part of the 2019 Senior Notes at a redemption price of 103.625% of the principal amount and reducing to 100% in April 2017 and thereafter. The 2019 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the 2019 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries. Additionally, the 2019 Senior Notes contain certain cross-default provisions, which could result in an event of default under the notes if the lenders under the

Revolver accelerate the Revolver obligations. Such an event of default, if it occurs, would permit the noteholders to accelerate the 2019 Senior Notes.

2020 Senior Notes

Our 8.5% 2020 Senior Notes due 2020 (the “2020 Senior Notes”), which were issued at par in April 2013, bear interest at an annual rate of 8.5% which is payable on May 1 and November 1 of each year. Beginning in May 2017, we may redeem all or part of the 2020 Senior Notes at a redemption price of 104.250% of the principal amount and reducing to 100% in May 2019 and thereafter. The 2020 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the 2020 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries. Additionally, the 2020 Senior Notes contain certain cross-default provisions, which could result in an event of default under the notes if the lenders under the Revolver accelerate the Revolver obligations. Such an event of default, if it occurs, would permit the noteholders to accelerate the 2020 Senior Notes.

Guarantees

The guarantees under the Revolver and the 2019 Senior Notes and 2020 Senior Notes are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. The parent company and its non-guarantor subsidiaries have no material independent assets or operations. There are no significant restrictions on the ability of the parent company or any of the Guarantor Subsidiaries to obtain funds through dividends, advances or loans.

10. Income Taxes

The following table summarizes our provision for income taxes for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Current income taxes (benefit)			
Federal	$ (660)	$ 2,045	$ —
State	1	1,504	—
	(659)	3,549	—
Deferred income tax benefit			
Federal	(261)	(130,693)	(77,046)
State	(4,451)	(4,534)	(650)
	(4,712)	(135,227)	(77,696)
	$ (5,371)	$ (131,678)	$ (77,696)

The following table reconciles the difference between the income tax benefit computed by applying the statutory tax rate to our loss before income taxes and our reported income tax benefit for the periods presented:

	Year Ended December 31,					
	2015		2014		2013	
Computed at federal statutory rate	$ (555,916)	35.0 %	$ (189,445)	35.0 %	$ (77,268)	35.0 %
State income taxes, net of federal income tax benefit	(4,438)	0.3 %	(3,556)	0.6 %	(650)	0.3 %
Change in valuation allowance	554,879	(35.0)%	61,104	(11.3)%	—	— %
Other, net	104	— %	219	— %	222	(0.1)%
	$ (5,371)	0.3 %	$ (131,678)	24.3 %	$ (77,696)	35.2 %

The following table summarizes the principal components of our deferred income tax assets and liabilities as of the dates presented:

	As of December 31,	
	2015	2014
Deferred tax assets:		
Property and equipment	$ 417,535	$ —
Pension and postretirement benefits	2,276	2,370
Share-based compensation	7,393	7,171
Net operating loss (“NOL”) carryforwards	222,971	102,098
Deferred gains	30,382	33,704
Other	16,637	19,875
	697,194	165,218
Less: Valuation allowance	(662,909)	(105,615)
Total net deferred tax assets	34,285	59,603
Deferred tax liabilities:		
Fair value of derivative instruments	34,285	57,707
Property and equipment	—	6,347
Total net deferred tax liabilities	34,285	64,054
Net deferred tax liabilities	$ —	$ 4,451

In 2015 and in connection with the retrospective application of ASU 2015–17, we reclassified $0.1 million of deferred income taxes previously classified as a component of current assets at December 31, 2014 as a reduction to our noncurrent deferred income tax liabilities.

As of December 31, 2015, we had federal NOL carryforwards of approximately $508.1 million, which, if not utilized, expire between 2032 and 2035, and state NOL carryforwards of approximately $69.4 million, which expire between 2024 and 2035. Because of the change in ownership provisions of the Tax Reform Act of 1986, use of a portion of our federal NOL may be limited in future periods.

As of December 31, 2014, we carried a valuation allowance against our federal and state deferred tax assets of $105.6 million. We incurred a pre-tax loss in 2015 which, when aggregated with the prior two years, resulted in a pre-tax loss for the three year period ended December 31, 2015. We considered both the positive and negative evidence in determining whether it was more likely than not that some portion or all of our deferred tax assets will be realized. On the basis of this evaluation, we increased the federal and state deferred tax asset valuation allowance by $557.3 million which resulted in an ending balance of $662.9 million as of December 31, 2015. The amount of deferred tax asset considered realizable could, however, be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as our projections for growth.

We had no liability for unrecognized tax benefits as of December 31, 2015 and 2014. There were no interest and penalty charges recognized during the years ended December 31, 2015, 2014 and 2013. Tax years from 2012 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

11. Firm Transportation Obligation

We have a contractual obligation for certain firm transportation capacity in the Appalachian region that expires in 2022 and, as a result of the sale of our natural gas assets in West Virginia, Kentucky and Virginia in 2012, we no longer have production to satisfy this commitment. While we sell our unused firm transportation to the extent possible, we recognized an obligation in 2012 representing the liability for estimated discounted future net cash outflows over the remaining term of the contract. The undiscounted amount payable on an annual basis for the each of the next five years is $2.7 million and a combined amount of $4.6 million is expected to be payable for 2021 through expiration in 2022.

The following table summarizes our firm transportation obligation and the changes therein for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Balance at beginning of period	$ 14,790	$ 15,993	$ 17,082
Accretion of obligations	942	1,301	1,674
Cash payments, net	(2,271)	(2,504)	(2,763)
Balance at end of period	$ 13,461	$ 14,790	$ 15,993

The accretion of this obligation, net of any recoveries from the periodic sale of our contractual capacity, is charged as an offset to Other revenue.

As of December 31, 2015, $2.8 million of the obligation is classified as current and is included in the Accounts payable and accrued liabilities while the remaining $10.7 million is classified as noncurrent and is included in the Other liabilities caption on our Condensed Consolidated Balance Sheets.

12. Additional Balance Sheet Detail

The following table summarizes components of selected balance sheet accounts as of the dates presented:

	As of December 31,	
	2015	2014
Other current assets:		
Tubular inventory and well materials	$ 2,878	$ 5,802
Prepaid expenses	4,184	4,215
Other	42	97
	$ 7,104	$ 10,114
Other assets: [1]		
Deferred issuance costs of the Revolver	$ 1,572	$ 1,623
Assets of supplemental employee retirement plan [2]	4,123	4,123
Other	2,655	95
	$ 8,350	$ 5,841
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 11,603	$ 122,994
Drilling and other lease operating costs	12,074	68,842
Royalties	39,119	78,359
Compensation-related [3]	9,904	9,197
Interest	15,531	15,555
Preferred stock dividends	—	6,067
Other	15,294	11,213
	$ 103,525	$ 312,227
Other liabilities:		
Deferred gains on sales of assets	$ 82,943	$ 90,569
Firm transportation obligation	10,705	12,042
Asset retirement obligations	2,621	5,890
Defined benefit pension obligations	1,129	1,753
Postretirement health care benefit obligations	731	890
Compensation-related [3]	1,447	7,630
Deferred compensation - supplemental employee retirement plan obligation and other [1]	4,434	4,183
Other	928	929
	$ 104,938	$ 123,886

[1] In connection with the adoption of ASU 2015–03 on a retrospective basis, we have reclassified $24.6 million of unamortized issuance costs associated with our senior notes at December 31, 2014 that were previously classified as a component of Other assets as a reduction to the carrying value of our long-term debt (see Note 9).

[2] Includes the assets and liabilities of the Penn Virginia Corporation Supplemental Employee Retirement Plan ("SERP") which is a nonqualified supplemental employee retirement savings plan. Assets of the SERP are held in a Rabbi Trust. Shares of our common stock held by the Rabbi Trust are presented for financial reporting purposes as treasury stock carried at cost.

[3] Includes liability-classified share-based compensation awards of $7.2 million and $2.9 million in Accounts payable and accrued expenses and an amount less than $0.1 million and $6.4 million in Other liabilities as of December 31, 2015 and 2014.

13. Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive upon the sale of an asset or that we would expect to pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We use a hierarchy that prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below.

Fair value measurements are classified and disclosed in one of the following three categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and long-term debt. As of December 31, 2015, the carrying values of all of these financial instruments, except the portion of long-term debt with fixed interest rates, approximated fair value.

The following table summarizes the fair value of our long-term debt with fixed interest rates, which is estimated based on the published market prices for these debt obligations as of the dates presented:

	December 31, 2015		December 31, 2014	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Notes due 2019	40,830	300,000	234,000	300,000
Senior Notes due 2020	125,473	775,000	620,000	775,000
	$ 166,303	$ 1,075,000	$ 854,000	$ 1,075,000

Recurring Fair Value Measurements

Certain financial assets and liabilities are measured at fair value on a recurring basis in our Consolidated Balance Sheets. The following tables summarize the valuation of those assets and liabilities as of the dates presented:

	As of December 31, 2015			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$ 97,956	$ —	$ 97,956	$ —
Assets of SERP	4,123	4,123	—	—
Liabilities:				
Deferred compensation – SERP obligation	(4,125)	(4,125)	—	—

	As of December 31, 2014			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$ 128,981	$ —	$ 128,981	$ —
Commodity derivative assets – noncurrent	35,897	—	35,897	—
Assets of SERP	4,123	4,123	—	—
Liabilities:				
Deferred compensation – SERP obligation	(4,178)	(4,178)	—	—

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one level of the fair value hierarchy to another level. In such instances, the transfer is deemed to have occurred at the beginning of the quarterly period in which the event or change in circumstances that caused the transfer occurred. There were no transfers during the years ended December 31, 2015, 2014 and 2013.

We used the following methods and assumptions to estimate fair values for the financial assets and liabilities described below:

- *Commodity derivatives*: We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for West Texas Intermediate crude oil and NYMEX Henry Hub gas closing prices as of the end of the reporting periods. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a level 2 input.
- *Assets of SERP*: We hold various publicly traded equity securities in a Rabbi Trust as assets for funding certain deferred compensation obligations. The fair values are based on quoted market prices, which are level 1 inputs.
- *Deferred compensation - SERP obligations*: Certain of our deferred compensation obligations are ultimately to be settled in cash based on the underlying fair value of certain assets, including those held in the Rabbi Trust. The fair values are based on quoted market prices, which are level 1 inputs.

Non-Recurring Fair Value Measurements

The most significant non-recurring fair value measurements utilized in the preparation of our Consolidated Financial Statements are those attributable to the recognition and measurement of net assets acquired, the recognition and measurement of asset impairments and the initial determination of AROs. The factors used to determine fair value for purposes of recognizing and measuring net assets acquired and asset impairments include, but are not limited to, estimates of proved and probable reserves, future commodity prices, indicative sales prices for properties, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs are typically not observable, we have categorized the amounts as level 3 inputs.

The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial estimates as level 3 inputs.

14. Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2015, by category, for the next five years and thereafter:

Year	Minimum Rentals	Drilling and Completion	Gathering and Intermediate Transportation	Firm Transportation	Drilling Carry	Other Commitments
2016	$ 2,606	$ 3,984	$ 15,328	$ 1,098	$ 1,900	$ 459
2017	2,542	—	12,319	1,095	8,764	274
2018	2,329	—	12,319	1,095	—	71
2019	1,341	—	12,319	1,095	—	—
2020	—	—	12,352	1,098	—	—
Thereafter	—	—	63,652	8,580	—	—
Total	$ 8,818	$ 3,984	$ 128,289	$ 14,061	$ 10,664	$ 804

Rental Commitments

Operating lease rental expense in the years ended December 31, 2015, 2014 and 2013 was $7.2 million, $8.7 million and $9.4 million, respectively, related primarily to field equipment, office equipment and office leases.

Drilling and Completion Commitments

In December 2015, we renegotiated an existing contractual commitment for our one remaining operated drilling rig to a lower daily rate and extended the expiration from February 2016 to August 2016. The remaining commitment under the new agreement was $3.4 million as of December 31, 2015. In September 2015, we renegotiated an existing commitment to purchase certain coiled tubing services at a lower rate and extended the expiration from December 31, 2015 to June 30, 2016. The minimum commitment remaining under this agreement was $0.6 million as of December 31, 2015. The drilling rig and coiled tubing services agreements include early termination provisions that would require us to pay penalties if we terminate the agreements prior to the end of their scheduled terms. The amount of the penalty is based on the number of days remaining in the contractual term. The penalty amount would have been $2.5 million had we had terminated our agreements on December 31, 2015.

In 2015, we reduced our total drilling rig count from eight to one. We incurred a total of $5.9 million in early termination charges with respect to these terminations in the year ended December 31, 2015, which have been reported as a component of Exploration expense on our Consolidated Statement of Operations.

Gathering and Intermediate Transportation Commitments

We have a long-term agreement for natural gas gathering, compression and gas lift services for a substantial portion of our natural gas production in the South Texas region through 2039. The agreement requires us to make certain minimum payments regardless of the volume of natural gas production for the first three years of the term. The minimum fee requirement remaining under this agreement is $5.0 million for 2016.

We also have long-term agreements for gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production in the South Texas region. Our payment obligations with respect to these services begin after the system has been constructed and is operational, which is currently expected in the first half of 2016. The agreements also require us to commit certain minimum volumes of crude oil production for the first ten years of the agreements' terms, which will result in minimum fee requirements of approximately $12.3 million on an annual basis.

Firm Transportation Commitments

We have entered into contracts that provide firm transportation capacity rights for specified volumes per day on various pipeline systems with terms that range from 1 to 13 years. The contracts require us to pay transportation demand charges regardless of the amount of the pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Drilling Carry

In connection with our August 2014 acquisition of undeveloped acreage in the Eagle Ford in Lavaca County, Texas, we committed to providing a drilling carry in the amount of $10.7 million to support development of this acreage through July 2017. If we have not incurred certain amounts of the drilling carry by certain dates in 2016 and 2017, we will be required to make a cash payment to the seller to satisfy any shortfall.

Other Commitments

We have entered into certain contractual arrangements for other products and services. We have minimum commitments under information technology licensing and service agreements, among others.

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. During 2010, we established a $0.9 million reserve for a litigation matter pertaining to certain properties that remains outstanding as of December 31, 2015.

Environmental Compliance

Extensive federal, state and local laws govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2015, we have recorded AROs of $2.6 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws, including any significant limitation on the use of hydraulic fracturing, have the potential to adversely affect our operations.

15. Shareholders' Equity

Preferred Stock

In June 2014, we completed a registered offering of 32,500 shares of our 6% Series B Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") that provided $313.3 million of proceeds, net of underwriting fees and issuance costs.

The annual dividend on each share of the Series B Preferred Stock is 6.00% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on January 15, April 15, July 15 and October 15 of each year. We may, at our option, pay dividends in cash, common stock or a combination thereof.

Each share of the Series B Preferred Stock is convertible, at the option of the holder, into a number of shares of our common stock equal to the liquidation preference of $10,000 divided by the conversion price, which is initially $18.34 per share and is subject to specified anti-dilution adjustments. The initial conversion rate is equal to 545.17 shares of our common stock for each share of the Series B Preferred Stock. The initial conversion price represents a premium of 30 percent relative to the last reported sales price of $14.11 per share prior to the offering of the Series B Preferred Stock. The Series B Preferred Stock is not redeemable by us or the holders at any time. At any time on or after July 15, 2019, we may, at our option, cause all outstanding shares of the Series B Preferred Stock to be automatically converted into shares of our common stock at the then-applicable conversion price if the closing sale price of our common stock exceeds 130% of the then-applicable conversion price for a specified period prior to conversion. If a holder elects to convert shares of the Series B Preferred Stock upon the occurrence of certain specified fundamental changes, we may be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option value.

In October 2012, we completed a registered offering of 11,500 shares of our 6% Series A Convertible Perpetual Preferred Stock (the "Series A Preferred Stock") that provided $110.3 million of proceeds, net of underwriting fees and issuance costs.

The annual dividend on each share of the Series A Preferred Stock is 6.00% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on January 15, April 15, July 15 and October 15 of each year. We may, at our option, pay dividends in cash, common stock or a combination thereof.

Each share of the Series A Preferred Stock is convertible, at the option of the holder, into a number of shares of our common stock equal to the liquidation preference of $10,000 divided by the conversion price, which is initially $6.00 per share and is subject to specified anti-dilution adjustments. The initial conversion rate is equal to 1,666.67 shares of our common stock for each share of the Series A Preferred Stock. The initial conversion price represents a premium of 20 percent relative to the 2012 common stock offering price of $5.00 per share. The Series A Preferred Stock is not redeemable by us or the holders at any time. At any time on or after October 15, 2017, we may, at our option, cause all outstanding shares of the Series A Preferred Stock to be automatically converted into shares of our common stock at the then-applicable conversion price if the closing sale price of our common stock exceeds 130% of the then-applicable conversion price for a specified period prior to conversion. If a holder elects to convert shares of the Series A Preferred Stock upon the occurrence of certain specified fundamental changes, we may be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option value.

In September 2015, we announced a suspension of quarterly dividends on the Series A Preferred Stock and Series B Preferred stock for the quarter ended September 30, 2015. The suspension was extended through December 31, 2015. Pursuant to the Eleventh Amendment, we are precluded from making dividend payments on our Series A and Series B Preferred Stock. Our articles of incorporation provide that any unpaid dividends will accumulate. While the accumulation does not result in presentation of a liability on the balance sheet, the accumulated dividends are deducted from our net income (or added to our net loss) in the determination of income (loss) attributable to common shareholders and the related earnings (loss) per share. For the year ended December 31, 2015, we accumulated a total of $10.7 million in unpaid preferred stock dividends, including $1.7 million attributable to the Series A Preferred Stock and $9.0 million attributable to the Series B Preferred Stock.

If we do not pay dividends on our Series A Preferred stock and B Preferred stock for six quarterly periods, whether consecutive or non-consecutive, the holders of the shares of both series of preferred stock, voting together as a single class, will have the right to elect two additional directors to serve on our board of directors until all accumulated and unpaid dividends are paid in full.

Common Stock

In May 2015, Penn Virginia's articles of incorporation were amended to increase the number of total authorized shares of common stock by 100 million to 228 million from 128 million.

In 2015, a total of 4,029 shares of the Series A Preferred Stock were converted into 6.7 million shares of our common stock and a total of 4,949 shares of the Series B Preferred Stock were converted into 2.7 million shares of our common stock. In 2014, a total of 3,555 shares of the Series A Preferred Stock were converted into 5.9 million shares of our common stock. We made payments of approximately $4.3 million in 2014 to induce the conversion of substantially all of these shares.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income and losses are entirely attributable to our pension and postretirement benefit obligations. The accumulated other comprehensive income, net of tax, were $0.4 million, $0.2 million and $0.3 million as of December 31, 2015, 2014 and 2013, respectively.

Treasury Stock

A portion of the compensation for certain non-employee members of our board of directors has been paid in deferred common stock units in recent years through the third quarter of 2015. Each deferred common stock unit represents one share of common stock, vests immediately upon issuance, and is available to the holder upon retirement from our board of directors. In addition, prior to 2012, certain of our employees made elective deferrals of compensation under the SERP, a portion of which was invested, at the employee's direction, in our common stock.

Shares of our common stock held by the SERP and deferred common stock units that have not been converted into common stock are presented for financial reporting purposes as treasury stock carried at cost. A total of 455,689 and 262,070 shares were recorded as treasury stock as of December 31, 2015 and 2014, respectively.

16. Share-Based Compensation and Other Benefit Plans

The Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (the "LTI Plan") permits the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. As of December 31, 2015, there were 2,226,571 shares available for issuance to employees and directors pursuant to the LTI Plan.

With the exception of performance-based restricted stock units ("PBRSUs"), all of the awards issued under our LTI Plan are classified as equity instruments because they result in the issuance of common stock on the date of grant, upon exercise or are otherwise payable in common stock upon vesting, as applicable. The compensation cost attributable to these awards is measured at the grant date and recognized over the applicable vesting period as a non-cash item of expense. Because the PBRSUs are payable in cash, they are considered liability-classified awards and are included in the Other liabilities caption on our Consolidated Balance Sheets. Compensation cost associated with the PBRSUs is measured at the end of each reporting period and recognized based on the period of time that has elapsed during each of the individual performance periods.

The following table summarizes share-based compensation expense recognized for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Equity-classified awards:			
Stock option awards	$ 1,704	$ 1,598	$ 3,123
Common, deferred, restricted and restricted unit awards	2,836	2,029	2,658
	4,540	$ 3,627	$ 5,781
Liability-classified awards	(711)	4,520	4,116
	$ 3,829	$ 8,147	$ 9,897

Stock Options

The exercise price of all stock options granted under the LTI Plan is equal to the fair market value of our common stock on the date of the grant. Options may be exercised at any time after vesting and prior to ten years following the date of grant. Options vest upon terms established by the compensation and benefits committee of our board of directors (the "Committee"). Generally, options vest over a three-year period, with one-third vesting in each year. In addition, all options will vest upon a change of control of us, as defined in the LTI Plan. In the case of employees, if a grantee's employment terminates (i) for cause, all of the grantee's options, whether vested or unvested, will be forfeited, (ii) by reason of death or disability, the grantee's options will vest and remain exercisable for one year and (iii) for any other reason, the grantee's unvested options will be forfeited and the grantee's vested options will remain exercisable for 90 days. For awards granted in 2013, all of the grantee's options will vest when the grantee becomes retirement eligible (age 62 and providing 10 consecutive years of service). For awards granted in 2012, all of the grantee's options will vest if or when the grantee retires following becoming retirement eligible. We have historically issued new shares to satisfy stock option exercises.

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option-pricing formula that uses the assumptions noted in the following table. Expected volatilities are based on historical changes in the market value of our stock. Separate groups of employees that have similar historical exercise behavior are considered separately to estimate expected lives. Options granted have a maximum term of ten years. We base the risk-free interest rate on the U.S. Treasury rate for the week of the grant having a term equal to the expected life of the option.

	2015	2014	2013
Expected volatility	64.6% to 69.4%	56.2% to 63.7%	56.9% to 70.1%
Dividend yield	0.00% to 0.00%	0.00% to 0.00%	0.00% to 0.00%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years	3.5 to 4.6 years
Risk-free interest rate	0.87% to 1.54%	0.82% to 1.63%	0.34% to 0.58%

The following table summarizes activity for our most recent fiscal year with respect to stock options:

	Shares Under Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at beginning of year	3,094,016	$ 16.89		
Granted	459,087	6.03		
Exercised	—	—		
Forfeited or expired	(469,282)	11.75		
Outstanding at end of year	3,083,821	$ 16.05	5.4	$ —
Exercisable at end of year	2,416,073	$ 18.28	4.6	$ —

The weighted-average grant-date fair value of options granted during the years ended December 31, 2015, 2014 and 2013, respectively, was $3.15, $7.46 and $2.35 per option. The total intrinsic value of options exercised during the years ended December 31, 2014, and 2013 was $2.3 million and less than $0.1 million, respectively. There were no options exercised during 2015.

As of December 31, 2015, we had $2.3 million of unrecognized compensation cost related to unvested stock options. We expect that cost to be recognized over a weighted-average period of 0.8 years. The total grant-date fair values of stock options that vested in 2015, 2014 and 2013 were $1.3 million, $1.8 million and $2.7 million, respectively.

Common Stock

A portion of the compensation paid to certain non-employee members of our board of directors is paid in common stock. Each share of common stock granted as compensation vests immediately upon issuance. In 2015, 2014 and 2013 respectively, we granted 195,395, 15,501 and 77,598 shares of common stock to our non-employee directors at a weighted-average grant date fair value of $1.33, $11.61 and $5.39 per share.

Deferred Common Stock Units

A portion of the compensation paid to certain non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, vests immediately upon issuance, and is available to the holder upon termination or retirement from our board of directors. Deferred common stock units awarded to directors receive all cash or other dividends we pay on shares of our common stock.

The following table summarizes activity for our most recent fiscal year with respect to awarded deferred common stock units:

	Deferred Common Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	253,879	$ 12.81
Granted	195,395	1.33
Converted	(1,776)	16.89
Balance at end of year	447,498	$ 7.75

As of December 31, 2015, 2014 and 2013, shareholders' equity included deferred compensation obligations of $3.4 million, $3.2 million and $2.8 million, respectively, and corresponding amounts for treasury stock.

Restricted Stock

Restricted stock vests upon terms established by the Committee and as specified in the award agreement. Restricted stock vests generally over a three-year period, with one-third vesting in each year. We recognize compensation expense on a straight-line basis over the vesting period.

There were no unvested restricted stock awards outstanding and no restricted stock vested during 2015, 2014 and 2013.

Restricted Stock Units

A restricted stock unit entitles the grantee to receive a share of common stock upon the vesting of the restricted stock unit or, at the discretion of the Committee, the cash equivalent of the fair market value of a share of common stock. The Committee determines the time period over which restricted stock units will vest. In addition, all restricted stock units will vest upon a change of control of us. Unless and to the extent the Committee determines otherwise, (i) if an employee's employment with us or our affiliates terminates for any reason other than death or disability, the grantee's restricted stock units will be forfeited and (ii) if a grantee dies or becomes disabled, the grantee's restricted stock units will vest. Awards granted prior to 2014 also vest if or when the grantee becomes retirement eligible. If restricted stock units vest early on account of retirement eligibility, payment on the restricted stock units will be made when the restricted stock units would have originally vested, even if that is after retirement. Restricted stock units generally vest over a three-year period, with one-third vesting in each year. Prior to 2013, the Committee, in its discretion, could grant tandem dividend equivalent rights with respect to restricted stock units. Beginning in 2013, the Committee may not grant dividend equivalent rights. A dividend equivalent right is a right to receive an amount in cash equal to, and 30 days after, the cash dividends made with respect to a share of common stock during the period such restricted stock unit is outstanding. Payments of dividend equivalent rights associated with restricted stock units that are expected to vest are recorded as dividends; payments associated with restricted stock units that are not expected to vest are recorded as compensation expense.

The following table summarizes activity for our most recent fiscal year with respect to awarded restricted stock units:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year [1]	599,347	$ 7.93
Granted	544,030	5.07
Vested	(422,504)	5.13
Forfeited	(251,887)	8.24
Balance at end of year [1]	468,986	$ 6.97

[1] Excludes 346,777 units at the beginning of the year and 346,777 units at the end of year that have vested due to retirement eligibility, but have not yet been settled or converted to common shares.

As of December 31, 2015, we had $3.7 million of unrecognized compensation cost attributable to unvested restricted stock units. We expect that cost to be recognized over a weighted-average period of 0.7 years. The total grant-date fair values of restricted stock units that vested in 2015, 2014 and 2013 were $2.2 million, $0.6 million and $1.7 million, respectively.

Performance-Based Restricted Stock Units

In May 2015, May 2014 and May 2013, we granted PBRSUs to certain executive officers. Vested PBRSUs are payable solely in cash on the third anniversary of the date of grant based upon the achievement of specified market-based performance metrics with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The number of PBRSUs vested can range from 0% to 200% of the initial grant. The PBRSUs do not have voting rights and do not participate in dividends.

Except as noted below, if the grantee's employment terminates for any reason prior to the third anniversary of the grant date, then the grantee's PBRSUs will be forfeited and no cash will be payable with respect to any PBRSUs. If the grantee's employment terminates for any reason other than cause prior to the third anniversary of the grant date, then all of the grantee's PBRSUs will vest and become payable in the amount and at the time the PBRSUs would have otherwise vested and been payable. Awards granted prior to 2014 also vest if or when the grantee becomes retirement eligible. If the grantee dies or becomes disabled prior to the third anniversary of the grant date, a pro-rated share (based on the number of days employed during the three-year vesting period) of the PBRSUs will vest and the grantee will be paid for such PBRSUs at the target percentage at the end of the original three-year vesting period. In the event of a change in control of us, all of the grantee's PBRSUs will immediately vest and the grantee will be paid for such PBRSUs following the change in control at the target percentage (regardless of our actual market-based performance) and using the value of our common stock on the effective date of the change in control (calculated as the closing price of our common stock on the effective date of the change in control).

The compensation cost of the PBRSUs is based on the fair value derived from a Monte Carlo model. The Monte Carlo model is a binomial valuation model that utilizes certain assumptions, including expected volatility, dividend yield, risk-free interest rates and a measure of total shareholder return.

The ranges for the assumptions used in the Monte Carlo model for the PBRSUs granted in 2015, 2014 and 2013 are as follows:

	2015	2014	2013
Expected volatility	66.5% to 97.7%	52.6% to 72.3%	51.3% to 66.7%
Dividend yield	0.0% to 0.0%	0.0% to 0.0%	0.0% to 0.0%
Risk-free interest rate	0.01% to 1.31%	0.02% to 1.07%	0.01% to 0.78%

The following table summarizes activity for our most recent fiscal year with respect to PBRSUs:

	Performance-Based Restricted Stock Units	Weighted-Average Fair Value
Balance at beginning of year	658,916	$ 16.29
Granted	282,181	7.38
Forfeited	—	—
Balance at end of year	941,097	$ 9.19

As of December 31, 2015, $7.2 million is included in the Accounts payable and accrued expenses caption and an amount less than $0.1 million is included in the Other liabilities caption on our Consolidated Balance Sheets.

Defined Contribution Plan

We maintain the Penn Virginia Corporation and Affiliated Companies Employees 401(k) Plan (the “401(k) Plan”), a defined contribution plan, which covers substantially all of our employees. We provide matching contributions on our employees’ elective deferral contributions up to six percent of compensation up to the maximum statutory limits. The 401(k) Plan also provides for discretionary employer contributions. The expense recognized with respect to the 401(k) Plan was $0.9 million, $1.7 million and $1.0 million for the years ended December 31, 2015, 2014, and 2013, respectively, and is included as a component of General and administrative expenses on our Statements of Operations. Amounts representing accrued obligations to the 401(k) Plan of $0.2 million and $0.3 million are included in the Accounts payable and accrued expenses caption on our Consolidated Balance Sheets as of December 31, 2015 and 2014, respectively.

Defined Benefit Pension and Postretirement Health Care Plans

We maintain unqualified legacy defined benefit pension and defined benefit postretirement plans which cover a limited population of former employees that retired prior to 2000. The combined expense recognized with respect to these plans was $0.1 million, $0.1 million and $0.3 million for the years ended December 31, 2015, 2014, and 2013, respectively, and is included as a component of General and administrative expenses on our Statements of Operations. The unfunded benefit obligations under these plans were $2.1 million and $2.8 million and are included within the Accounts payable and accrued expenses and Other liabilities captions on our Consolidated Balance Sheets as of December 31, 2015 and 2014, respectively.

17. Impairments

The following table summarizes impairment charges recorded during the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Oil and gas properties	$ 1,396,340	$ 791,809	$ 132,224
Other – tubular inventory and well materials	1,084	—	—
	$ 1,397,424	$ 791,809	$ 132,224

The following table summarizes the aggregate fair values of the assets described below, by asset category and the classification of inputs within the fair value measurement hierarchy, at the respective dates of impairment:

	Fair Value Measurement	Level 1	Level 2	Level 3
Year ended December 31, 2015:				
Long-lived assets held for use	$ 311,886	$ —	$ —	$ 311,886
Year ended December 31, 2014:				
Long-lived assets held for use	$ 65,203	$ —	$ —	$ 65,203
Long-lived assets sold during the year	70,733	$ —	$ —	$ 70,733
Year ended December 31, 2013:				
Long-lived assets held for use	$ 93,945	$ —	$ —	$ 93,945

The significant deterioration of commodity prices in 2015, as reflected in the future strip pricing as of December 31, 2015, triggered an impairment of approximately $1.4 billion to our proved and unproved Eagle Ford properties, which required us to reduce their carrying value to a fair value of approximately $312 million. In 2015, we also recorded an impairment charge of $1.1 million attributable to surplus tubular inventory and well materials. In 2014, we recognized oil and gas asset impairments of: (i) $667.8 million in the East Texas, Granite Wash and Marcellus regions due to the decline in commodity prices in the fourth quarter of 2014, (ii) $6.1 million in connection with an uneconomic field drilled in the Mid-Continent region and (iii) $117.9 million to write-down our Selma Chalk assets in Mississippi triggered by the disposition of those properties. In 2013, we recognized oil and gas impairments of: (i) $121.8 million in the Granite Wash, (ii) $9.5 million in the Marcellus Shale and (iii) $0.9 million in the Selma Chalk, in each case due primarily to declines in natural gas prices.

18. Interest Expense

The following table summarizes the components of interest expense for the periods presented:

	Year Ended December 31, 2015	2014	2013
Interest on borrowings and related fees	$ 92,490	$ 91,866	$ 80,263
Accretion of original issue discount [1]	—	—	431
Amortization of debt issuance costs	4,749	4,197	3,413
Capitalized interest	(6,288)	(7,232)	(5,266)
	$ 90,951	$ 88,831	$ 78,841

[1] Includes accretion of original issue discount attributable to the 2016 Senior Notes that were retired in 2013.

19. Earnings per Share

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Net loss	$ (1,582,961)	$ (409,592)	$ (143,070)
Less: Preferred stock dividends [1]	(22,789)	(17,148)	(6,900)
Less: Induced conversion of preferred stock	—	(4,256)	—
Net loss attributable to common shareholders – basic and diluted	$ (1,605,750)	$ (430,996)	$ (149,970)
Weighted-average shares – basic	73,639	68,887	62,335
Effect of dilutive securities [2]	—	—	—
Weighted-average shares – diluted	73,639	68,887	62,335

[1] Preferred stock dividends were excluded from diluted earnings per share for the years ended December 31, 2015, 2014 and 2013, as the assumed conversion of the outstanding preferred stock would have been anti-dilutive.

[2] For 2015 and 2014, approximately 30.2 million and 26.6 million potentially dilutive securities, including the Series A and Series B Preferred Stock, stock options and restricted stock units had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share. For 2013, approximately and 19.8 million, respectively, potentially dilutive securities, including the Series A Preferred Stock, stock options and restricted stock units had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share.

Supplemental Quarterly Financial Information (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2015				
Revenues [1]	$ 74,527	$ 83,616	$ 111,984	$ 35,171
Operating income (loss) [2]	$ (57,876)	$ (40,982)	$ 3,604	$ (1,469,787)
Income (loss) attributable to common shareholders	$ (63,232)	$ (86,196)	$ 19,965	$ (1,476,287)
Income (loss) per share – basic [3]	$ (0.88)	$ (1.19)	$ 0.27	$ (19.32)
Income (loss) per share – diluted [3]	$ (0.88)	$ (1.19)	$ 0.25	$ (19.32)
Weighted-average shares outstanding:				
Basic	71,820	72,398	72,651	76,430
Diluted	71,820	72,398	103,452	76,430
2014				
Revenues [4]	$ 189,865	$ 139,361	$ 205,396	$ 102,151
Operating income (loss) [5]	$ 71,684	$ (91,636)	$ 85,921	$ (681,954)
Income (loss) attributable to common shareholders [6]	$ 17,503	$ (105,870)	$ 81,132	$ (423,761)
Income (loss) per share – basic [3]	$ 0.27	$ (1.59)	$ 1.13	$ (5.90)
Income (loss) per share – diluted [3]	$ 0.22	$ (1.59)	$ 0.87	$ (5.90)
Weighted-average shares outstanding:				
Basic	65,611	66,514	71,536	71,790
Diluted	85,744	66,514	103,606	71,790

[1] Includes gains (losses) on sales of property and equipment of $ 50.8 million and $(9.5) million during the quarters ended September 30, 2015 and December 31, 2015, respectively.
[2] Includes impairments of oil and gas properties of $1.4 billion for the quarter ended December 31, 2015.
[3] The sum of the quarters may not equal the total of the respective year's earnings per common share due to changes in weighted-average shares outstanding throughout the year.
[4] Includes gains on sales of property and equipment of $56.8 million and $63.5 million during the quarters ended March 31, 2014 and September 30, 2014, respectively.
[5] Includes impairments of oil and gas properties of $117.9 million, $6.1 million and $667.8 million during the quarters ended June 30, 2014, September 30, 2014 and December 31, 2014, respectively.
[6] Includes other income of $154.1 million attributable to our commodity derivatives during the quarter ended December 31, 2014.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Oil and Gas Reserves

All of our proved oil and gas reserves are located in the continental United States. The estimates of our proved oil and gas reserves were prepared by our independent third party engineers, DeGolyer and MacNaughton, Inc. utilizing data compiled by us. DeGolyer and MacNaughton, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petro physicists. Our Vice President, Operations & Engineering is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc.

Reserve engineering is a process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, NGLs and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future prices for these commodities may all differ from those assumed. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available.

The following table sets forth our estimate of net quantities of proved reserves, including changes therein and proved developed and proved undeveloped reserves for the periods presented:

Proved Developed and Undeveloped Reserves	**Oil (MBbl)**	**NGLs (MBbl)**	**Natural Gas (MMcf)**	**Total Equivalents (MBOE)**
December 31, 2012	24,851	20,691	407,519	113,462
Revisions of previous estimates	(4,400)	(5,298)	(111,939)	(28,355)
Extensions, discoveries and other additions	34,077	6,510	36,297	46,637
Production	(3,435)	(983)	(14,435)	(6,824)
Purchase of reserves	9,604	1,046	4,651	11,425
Sale of reserves in place	—	—	—	—
December 31, 2013	60,697	21,966	322,093	136,345
Revisions of previous estimates	(8,286)	(7,727)	(98,386)	(32,411)
Extensions, discoveries and other additions	21,427	6,090	31,842	32,824
Production	(4,644)	(1,110)	(13,084)	(7,934)
Purchase of reserves	—	—	—	—
Sale of reserves in place	(188)	—	(83,200)	(14,055)
December 31, 2014	69,006	19,219	159,265	114,769
Revisions of previous estimates	(34,525)	(8,667)	(46,859)	(51,002)
Extensions, discoveries and other additions	2,519	321	1,584	3,105
Production	(4,923)	(1,381)	(9,713)	(7,923)
Purchase of reserves	—	—	—	—
Sale of reserves in place	(2,615)	(2,288)	(62,124)	(15,258)
December 31, 2015	29,462	7,204	42,153	43,691
Proved Developed Reserves:				
December 31, 2013	19,306	8,541	163,161	55,041
December 31, 2014	22,054	8,065	94,565	45,880
December 31, 2015	20,188	6,201	37,172	32,585
Proved Undeveloped Reserves:				
December 31, 2013	41,391	13,425	158,932	81,304
December 31, 2014	46,952	11,154	64,700	68,889
December 31, 2015	9,274	1,003	4,981	11,106

The following is a discussion and analysis of the significant changes in our proved reserve estimates for the periods presented:

Year Ended December 31, 2015

We had downward revisions of 51.0 MMBOE primarily as a result of the following: (i) downward revisions of 45.2 MMBOE due to the removal of proved undeveloped locations that would not be developed within five years primarily in the Eagle Ford, (ii) downward revisions of 2.9 MMBOE attributable to certain proved wells in the Eagle Ford and (iii) downward revisions of 2.5 MMBOE due to well performance issues, primarily in the Granite Wash in Oklahoma. We added 3.1 MMBOE due primarily to the drilling of 61 gross (38.6 net) wells and the addition of proved undeveloped locations in the Eagle Ford. We sold our Cotton Valley and Haynesville Shale assets in East Texas as well as certain non-core Eagle Ford wells resulting in a decrease of 15.3 MMBOE.

Year Ended December 31, 2014

We had downward revisions of 32.4 MMBOE primarily as a result of the following: (i) downward revisions of 20.7 MMBOE due to the removal of proved undeveloped locations that would not be developed within five years primarily in the Cotton Valley and Haynesville Shale (19.1 MMBOE) and the Granite Wash (1.6 MMBOE), (ii) downward revisions of 8.3 MMBOE (4.5 MMBOE of proved developed and 3.8 MMBOE of proved undeveloped) attributable to certain proved wells in the Eagle Ford and (iii) downward revisions of 3.4 MMBOE due to well performance issues (2.3 MMBOE in the Cotton Valley and Haynesville Shale and 1.1 MMBOE in the Granite Wash). We added 32.8 MMBOE due primarily to the drilling of 84 gross (51.6 net) wells and the addition of proved undeveloped locations in the Eagle Ford. We sold our Selma Chalk assets in Mississippi as well as certain wells in Oklahoma resulting in a decrease of 14.1 MMBOE.

Year Ended December 31, 2013

We had downward revisions of 28.4 MMBOE primarily as a result of the following: (i) downward revisions of 20.1 MMBOE due to the removal of proved undeveloped locations that would not be developed within five years primarily in the Haynesville Shale (8.3 MMBOE), Cotton Valley (7.1 MMBOE), Selma Chalk (3.7 MMBOE) and all other locations combined, including the Granite Wash and Marcellus Shale (1.0 MMBOE), (ii) downward revisions in the Eagle Ford due primarily to the elimination of certain locations (2.2 MMBOE) and revisions to existing locations (2.5 MMBOE) attributable to changes in our development plans including the effects of reduced down-spacing, (iii) downward revisions of 5.8 MMBOE due to well performance issues, primarily in the Haynesville Shale, the Cotton Valley and the Selma Chalk and (iv) the effects of non-participation and lease expirations (0.3 MMBOE) partially offset by (v) favorable price revisions (2.5 MMBOE) for oil and natural gas. We added 46.6 MMBOE due primarily to the drilling of 59 gross (34.6 net) wells and the addition of proved undeveloped locations as well as 11.4 MMBOE from the Eagle Ford Acquisition.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth capitalized costs related to our oil and gas producing activities and accumulated DD&A for the periods presented:

	As of December 31,		
	2015	**2014**	**2013**
Oil and gas properties:			
Proved	$ 2,678,415	$ 3,390,482	$ 2,970,047
Unproved	6,881	125,676	101,520
Total oil and gas properties	2,685,296	3,516,158	3,071,567
Other property and equipment	11,330	55,601	87,412
Total capitalized costs relating to oil and gas producing activities	2,696,626	3,571,759	3,158,979
Accumulated depreciation and depletion	(2,354,405)	(1,749,752)	(924,667)
Net capitalized costs relating to oil and gas producing activities [1]	$ 342,221	$ 1,822,007	$ 2,234,312

[1] Excludes property and equipment attributable to our corporate operations which is comprised of certain capitalized hardware, software and office furniture and fixtures.

Costs Incurred in Certain Oil and Gas Activities

The following table summarizes costs incurred in our oil and gas property acquisition, exploration and development activities for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Proved property acquisition costs [1]	$ —	$ —	$ 277,888
Unproved property acquisition costs [1]	16,052	98,443	188,202
Exploration costs [2]	939	5,966	16,833
Development costs and other [3]	294,445	690,277	422,540
Total costs incurred	$ 311,436	$ 794,686	$ 905,463

[1] Acquisition costs in 2013 includes $277.9 million and $119.7 million of proved and unproved property attributable to the Eagle Ford Acquisition.

[2] Includes geological and geophysical costs of $0.8 million, $5.1 million and $2.9 million and delay rentals of $0.1 million, $0.9 million and $0.7 million during the years ended December 31, 2015, 2014 and 2013, respectively.

[3] Includes drilling rig termination charges of $5.9 million and $0.8 million during the years ended December 31, 2015 and 2014, respectively, that were charged to exploration expense. Does not include non-cash ARO assets of $0.3 million, $0.4 million and $1.7 million that were added to capitalized costs relating to oil and gas producing activities during the years ended December 31, 2015, 2014 and 2013, respectively.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Future cash inflows were computed by applying the average prices of oil and gas during the 12-month period prior to the period end, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated costs as of that fiscal year end, to the estimated future production of proved reserves. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available NOL carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

The standardized measure of discounted future net cash flows is not intended, and should not be interpreted, to represent the fair value of our oil and gas reserves. An estimate of the fair value would also consider, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and cost, and a discount factor more representative of economic conditions and risks inherent in reserve estimates. Accordingly, the changes in standardized measure reflected above do not necessarily represent the economic reality of such transactions.

Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu with the representative price of natural gas adjusted for basis premium and energy content to arrive at the appropriate net price. NGL prices were estimated as a percentage of the base crude oil price. The following table summarizes the price measurements utilized, by product, with respect to our estimates of proved reserves as well as in the determination of the standardized measure of the discounted future net cash flows for the periods presented:

	Crude Oil	NGLs	Natural Gas
	$ per Bbl	$ per Bbl	$ per MMBtu
As of December 31, 2013	$ 103.11	$ 31.10	$ 3.47
As of December 31, 2014	$ 92.91	$ 25.49	$ 4.32
As of December 31, 2015	$ 45.78	$ 13.15	$ 2.70

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Future cash inflows	$ 1,557,246	$ 7,589,354	$ 8,059,089
Future production costs	(731,951)	(2,239,491)	(2,193,925)
Future development costs	(206,616)	(2,175,530)	(2,111,918)
Future net cash flows before income tax	618,679	3,174,333	3,753,246
Future income tax expense	—	(686,562)	(973,680)
Future net cash flows	618,679	2,487,771	2,779,566
10% annual discount for estimated timing of cash flows	(295,368)	(1,305,326)	(1,515,788)
Standardized measure of discounted future net cash flows	$ 323,311	$ 1,182,445	$ 1,263,778

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table summarizes the changes in the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	Year Ended December 31,		
	2015	2014	2013
Sales of oil and gas, net of production costs	$ (180,455)	$ (418,300)	$ (359,989)
Net changes in prices and production costs	(1,442,919)	(222,349)	49,214
Changes in future development costs	1,376,226	624,068	299,542
Extensions, discoveries and other additions	19,396	261,410	995,858
Development costs incurred during the period	222,612	380,650	79,964
Revisions of previous quantity estimates	(436,898)	(614,497)	(260,440)
Purchases of reserves-in-place	—	—	219,414
Sale of reserves-in-place	(86,662)	(44,805)	—
Changes in production rates	(767,689)	(382,015)	(68,652)
Accretion of discount	147,245	171,663	69,247
Net change in income taxes	290,010	162,842	(258,254)
Net increase (decrease)	(859,134)	(81,333)	765,904
Beginning of year	1,182,445	1,263,778	497,874
End of year	$ 323,311	$ 1,182,445	$ 1,263,778

Item 9 Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A Controls and Procedures

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2015. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported accurately and on a timely basis. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2015, such disclosure controls and procedures were effective.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. This evaluation was completed based on the framework established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our management has concluded that, as of December 31, 2015, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

KPMG LLP, an independent registered public accounting firm, has issued an attestation report on the internal control over financial reporting as of December 31, 2015, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B Other Information

On March 15, 2016, we entered into an Eleventh Amendment (the "Eleventh Amendment") to our Credit Agreement, dated as of September 28, 2012 (the "Credit Agreement," and also referred to in this Annual Report on Form 10-K as the "Revolver"), by and among Penn Virginia Holding Corp. (the "Borrower"), Penn Virginia Corporation (the "Parent"), each subsidiary (other than the Borrower) of the Parent party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent and as the issuing bank.

The Eleventh Amendment provides (i) for an extension before certain events of default under the Credit Agreement will occur, (ii) a reduction in commitments to $171.8 million and (iii) that the borrowing base under the Credit Agreement is not subject to scheduled redetermination until May 15, 2016. Specifically, the extension period with respect to events of default is through 12:01 am on April 12, 2016, which can be further extended through 12:01 am on May 10, 2016 if certain conditions have been satisfied. The extension period can be terminated early upon certain triggering events.

The key conditions to the first extension (April 12, 2016) and entry to the Eleventh Amendment are: (i) termination of certain hedge agreements and application of the proceeds against the loans (which will result in a further reduction of our lenders' commitments), (ii) entry into control agreements over deposit accounts, subject to customary exceptions, (iii) payment of advisor fees, and (iv) agreement to certain changes to the Credit Agreement, including increasing the interest rate by 1.00%, tightening certain restrictive covenants and agreeing that monthly hedge settlements will be applied against the loans (which will result in a further reduction in our lenders' commitments).

The key conditions to the second extension (May 10, 2016) are: (i) termination of certain additional hedges and application of most of the proceeds against the loans (which will result in a further reduction in our lenders' commitments) and (ii) no notification by the representative of the ad hoc committee of unsecured noteholders that they do not support such extension.

The foregoing description of the Eleventh Amendment is a summary only and is qualified in its entirety by reference to the complete text of the Eleventh Amendment, a copy of which is attached as Exhibit 10.1.11to this Annual Report on Form 10-K and incorporated herein by reference.

Part III

Item 10 Directors, Executive Officers and Corporate Governance

Information Regarding Directors

The following table sets forth certain information regarding each of our directors:

Age, Business Experience, Other Directorships and Qualifications	Director of the Company Since
John U. Clarke, age 63	2009 [1,2,3]

Mr. Clarke has been a Partner with Turnbridge Capital, LLC, an energy-focused private equity investment firm, since May 2011. He has also served as President of Concept Capital Group, Inc., a financial and strategic consulting firm founded by him in 1995, since November 2009, a position he also held from 2001 to 2004 and from 1995 to 1996. From 2004 until its sale in November 2009, Mr. Clarke served as Chairman and Chief Executive Officer of NATCO Group Inc., an oil services company. Previously, Mr. Clarke served as Managing Director of SCF Partners, a private equity investment firm (2000 to 2001), Executive Vice President and Chief Financial Officer of Dynegy, Inc., an energy trading company (1997 to 2000), Managing Director of Simmons & Co. International, an energy investment banking firm (1996 to 1997), and Executive Vice President and Chief Financial and Administrative Officer of Cabot Oil & Gas Corporation, an oil and gas exploration and production company, or Cabot (1993 to 1995). He was employed by Transco Energy Company, an interstate pipeline company, from 1981 to 1993, last serving as Senior Vice President and Chief Financial Officer, and by Tenneco Inc., an interstate pipeline company, from 1977 to 1981 in the finance department.

In the last five years, Mr. Clarke has also served on the board of directors of Glori Energy Inc. (April 2011 to June 2015) and Tesco Corporation (August 2011 to September 2013).

Mr. Clarke has served for over 30 years as a director or executive officer at numerous companies engaged in several businesses in or related to the energy industry. In his various capacities, Mr. Clarke has provided these companies with strategic, financial and operational oversight and leadership. This experience allows him to provide guidance to the Board on a wide spectrum of strategic, financial and operational matters and effectively chair the Compensation and Benefits Committee.

Edward B. Cloues, II, age 68	2001

Mr. Cloues has served as the Chairman of the Board of the Company since May 2011 (non-executive Chairman to October 2015) and as our Chief Executive Officer since October 2015. He also serves as the non-executive Chairman of the Board of AMREP Corporation (director since September 1994 and Chairman since January 1996) and on the board of directors of Hillenbrand, Inc. (since April 2010). Mr. Cloues served as a director (since January 2003) and as the non-executive Chairman of the Board (since July 2011) of PVR GP, LLC, the general partner of PVR Partners, L.P., until its sale in March 2014.

Mr. Cloues served as Chairman of the Board and Chief Executive Officer of K-Tron International, Inc., a provider of material handling equipment and systems, from January 1998 until its sale in April 2010, and was a director of that company from July 1985 to April 2010. Prior to joining K-Tron International, Inc. as its Chairman of the Board and Chief Executive Officer, Mr. Cloues was a Partner at Morgan, Lewis & Bockius LLP, a global law firm, from October 1979 to January 1998.

As a former law firm partner specializing in business law matters, the former Chairman of the Board and Chief Executive Officer of K-Tron International, Inc. and a director of multiple public companies, Mr. Cloues has extensive leadership experience and familiarity with complex mergers and acquisitions and other transactions, as well as considerable background in financial, strategic, corporate governance and executive compensation matters.

Steven W. Krablin, age 65	2010 [1,2,3]

Mr. Krablin served as President, Chief Executive Officer and Chairman of the Board of T-3 Energy Services, Inc., a provider of a broad range of oilfield products and services used in the drilling and completion of new oil and gas wells, the workover of existing wells and the production and transportation of oil and gas, from March 2009 until its sale in January 2011. For the last five years and from April 2005 until his employment with T-3 Energy Services, Inc., Mr. Krablin was a private investor. From January 1996 to his retirement in April 2005, Mr. Krablin served as Senior Vice President and Chief Financial Officer of National-Oilwell, Inc., a manufacturer and distributor of oil and gas drilling equipment and other oilfield products. From 1986 to 1996, Mr. Krablin was employed by Enterra Corporation, a provider of rental and fishing tools to the oil and gas industry, last serving as Vice President and Chief Financial Officer.

Mr. Krablin currently serves on the boards of directors of Chart Industries, Inc. (since July 2006), Hornbeck Offshore Services, Inc. (since August 2005) and Precision Drilling Corporation (since May 2015).

Mr. Krablin has extensive energy industry experience, having served as the chief executive officer of an oilfield products company and as the chief financial officer of several oil and gas equipment companies. The Board utilizes this experience when considering a broad range of financial and operational matters. In addition, Mr. Krablin also previously served as our director for over five years. Mr. Krablin's knowledge of our history, our operations and our personnel assists him in providing valuable guidance to the Board.

Marsha R. Perelman, age 65 1998 [1,3]

Ms. Perelman has served as Chief Executive Officer of Woodforde Management, Inc., a holding company founded by her, since 1993. From 1983 to 1990, Ms. Perelman served as President of Clearfield Ohio Holdings, Inc., a gas gathering and distribution company co-founded by her, and as Vice President of Clearfield Energy, Inc., a crude oil gathering and distribution company co-founded by her.

Ms. Perelman served on the board of directors of PVR GP, LLC, the general partner of PVR Partners, L.P., from May 2005 until its sale in March 2014.

Ms. Perelman's background in the energy and other industries has enabled her to contribute significantly to our strategic direction. In addition, Ms. Perelman's professional and personal contacts have helped the Nominating and Governance Committee identify and recruit director candidates.

H. Baird Whitehead, age 65 2011

Mr. Whitehead served as our Chief Executive Officer from May 2011 to October 2015, as our President from February 2011 to October 2015 and as President of Penn Virginia Oil & Gas Corporation from January 2001 to October 2015. He also served as our Chief Operating Officer from February 2009 to May 2011 and as our Executive Vice President from January 2001 to February 2011. Prior to joining the Company, Mr. Whitehead served in various positions with Cabot. From 1998 to 2001, Mr. Whitehead served as Senior Vice President during which time he oversaw Cabot's drilling, production and exploration activity in the Appalachian, Rocky Mountain, Mid-Continent and Texas and Louisiana Gulf Coast areas. From 1992 to 1998, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Appalachian business. From 1989 to 1992, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Anadarko business unit.

Mr. Whitehead has served in senior management positions with oil and gas exploration and production companies for over 20 years. His broad experience in the exploration and production industry and detailed knowledge of our operations lends critical support to the Board's decision making process.

Gary K. Wright, age 71 2003 [1,2,3]

Mr. Wright has acted as an independent consultant since 2004. From 2003 to 2004, he served as President of LNB Energy Advisors, a provider of bank credit facilities and strategic advice to small to mid-sized oil and gas producers. From 2001 to 2003, Mr. Wright was an independent consultant to the energy industry. From 1992 to 2001, Mr. Wright served in various capacities with the Global Oil and Gas Group of Chase Manhattan Bank, including as North American Credit Deputy from 1998 to 2001 and as Managing Director and Senior Client Manager in the Southwest from 1992 to 1998. Prior to joining Chase Manhattan Bank, Mr. Wright served as Manager of the Chemical Bank Worldwide Energy Group (1990 to 1992), as Manager of Corporate Banking with Texas Commerce Bank (1987 to 1990) and as Manager of the Energy Group of Texas Commerce Bank (1982 to 1990).

Mr. Wright has broad experience providing financial and strategic advice to oil and gas producers and other companies in the energy business. The Board draws on this experience when it considers financial and economic analyses related to financing and other transactions. In addition, Mr. Wright's financial expertise assists him in effectively chairing the Audit Committee.

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1 Member of the Nominating and Governance Committee.

2 Member of the Compensation and Benefits Committee

3 Member of the Audit Committee

Executive Officers

The following table sets forth certain information regarding each of our executive officers:

Age, Position with the Company and Business Experience	Officer of the Company Since
Edward B. Cloues, II, age 68 (see above)	2015
Steven A. Hartman, age 48	2010

Mr. Hartman has served as our Senior Vice President and Chief Financial Officer since December 2010. He served as our Vice President and Treasurer from July 2006 to December 2010, as our Assistant Treasurer and Treasury Manager from September 2004 to July 2006 and as our Manager, Corporate Development from August 2003 to September 2004. Mr. Hartman also served as Vice President and Treasurer of PVG GP, LLC, the general partner of Penn Virginia GP Holdings, L.P., from September 2006 to June 2010 and of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P., from July 2006 to June 2010. Prior to joining the Company, Mr. Hartman was employed by El Paso Corporation and its publicly traded spin-off, GulfTerra Energy Partners, L.P., in a variety of financial and corporate-development related positions.

Nancy M. Snyder, age 63	1997

Ms. Snyder has served as our Executive Vice President since May 2006, as our Chief Administrative Officer since May 2008, as our Senior Vice President from February 2003 to May 2006, as our Vice President from December 2000 to February 2003 and as our General Counsel and Corporate Secretary since September 1997. Ms. Snyder also served as Vice President and General Counsel of PVG GP, LLC, the general partner of Penn Virginia GP Holdings, L.P., from September 2006 to June 2010 and as Chief Administrative Officer from May 2008 to June 2010 and as Vice President and General Counsel of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P., from July 2001 to June 2010 and as Chief Administrative Officer from May 2008 and June 2010. Ms. Snyder has also served on the board of directors of SunCoke Energy Partners GP LLC, the general partner of SunCoke Energy Partners, L.P. since January 2013.

John A. Brooks, age 54	1997

Mr. Brooks has served as our Executive Vice President and Chief Operating Officer since January 2014. He also served as our Executive Vice President, Operations from February 2013 to January 2014, as our Senior Vice President from February 2012 to February 2013, as our Vice President from May 2008 to February 2012, as Vice President and Regional Manager of Penn Virginia Oil & Gas Corporation from October 2007 to February 2012, as Operations Manager of Penn Virginia Oil & Gas Corporation from January 2005 to October 2007 and as Drilling Manager of Penn Virginia Oil & Gas Corporation from February 2002 to January 2005.

Role of the Board

Our business is managed under the direction of the Board of the Company, or the Board. The Board has adopted Corporate Governance Principles describing its duties. A copy of our Corporate Governance Principles is available at the “Corporate Governance” section of our website, http://www.pennvirginia.com. The Board meets regularly to review significant developments affecting the Company and to act on matters requiring Board approval.

Code of Business Conduct and Ethics

The Board has adopted a Code of Business Conduct and Ethics as its “code of ethics” as defined in Item 406 of Regulation S-K, which applies to all of our directors, officers, employees and consultants, including our Chief Executive Officer, or our CEO, Chief Financial Officer, or our CFO, principal accounting officer or controller or persons performing similar functions. A copy of our Code of Business Conduct and Ethics is available at the “Corporate Governance” section of our website, http://www.pennvirginia.com. We intend to satisfy the disclosure requirement for any future amendments to, or waivers of, our Code of Business Conduct and Ethics by posting such information on our website.

Communications with the Board

Shareholders and other interested parties may communicate any concerns they have regarding us by contacting Mr. Cloues in writing at c/o Corporate Secretary, Penn Virginia Corporation, Four Radnor Corporate Center, Suite 200, 100 Matsonford Road, Radnor, Pennsylvania 19087.

Committees of the Board

The Board has a Nominating and Governance Committee, a Compensation and Benefits Committee and an Audit Committee. Each of the Board's committees acts under a written charter, which was adopted and approved by the Board. Copies of the committees' charters are available at the "Corporate Governance" section of our website, http://www.pennvirginia.com.

Nominating and Governance Committee. Messrs. Clarke, Krablin and Wright and Ms. Perelman are the members of the Nominating and Governance Committee, or the N&G Committee, and each is an Independent Director, as such term is defined in Item 13, "Certain Relationships and Related Transactions, and Director Independence-Director Independence." The N&G Committee (i) seeks, identifies and evaluates individuals who are qualified to become members of the Board, (ii) recommends to the Board candidates to fill vacancies on the Board, as such vacancies occur and (iii) recommends to the Board the slate of nominees for election as directors by our shareholders at each Annual Meeting of Shareholders. The N&G Committee will consider nominees recommended by shareholders. Shareholder recommendations for director nominees will receive the same consideration by the Board's N&G Committee that other nominations receive. The N&G Committee recommends individuals as director nominees based on professional, business and industry experience, ability to contribute to some aspect of our business and willingness to commit the time and effort required of a director. The N&G Committee may also consider whether and how a director candidate's views, experience, skill, education or other attributes may contribute to the Board's diversity. While the N&G Committee does not require that each individual director candidate contribute to the Board's diversity, the N&G Committee in general strives, and has succeeded, to ensure that the Board, as a group, is comprised of individuals with diverse backgrounds and experience conducive to understanding and being able to contribute to all financial, operational, strategic and other aspects of our business. Director nominees must possess good judgment, strength of character, a reputation for integrity and personal and professional ethics and an ability to think independently while contributing to a group process. The N&G Committee also recommends to the Board the individual to serve as Chairman of the Board. Additionally, the N&G Committee assists the Board in implementing our Corporate Governance Principles, our non-employee director stock ownership guidelines and our executive officer stock ownership guidelines, confirms that the Compensation and Benefits Committee evaluates senior management, oversees Board self-evaluation through an annual review of Board and committee performance and assists the Independent Directors in establishing succession policies in the event of an emergency or retirement of our CEO. The N&G Committee may obtain advice and assistance from outside director search firms as it deems necessary to carry out its duties.

Compensation and Benefits Committee. Messrs. Clarke, Krablin and Wright are the members of the Compensation and Benefits Committee, or the C&B Committee, and each is an Independent Director. The C&B Committee is responsible for determining the compensation of our executive officers. The C&B Committee reviews and discusses with management the information contained in Item 11, "Executive Compensation-Compensation Discussion and Analysis" and recommends that such information be included herein. The C&B Committee also periodically reviews and makes recommendations or decisions regarding our incentive compensation and equity-based plans, provides oversight with respect to our other employee benefit plans and reports its decisions and recommendations with respect to such plans to the Board. The C&B Committee also reviews and makes recommendations to the Board regarding our director compensation policy. The C&B Committee may obtain advice and assistance from outside compensation consultants and other advisors as it deems necessary to carry out its duties.

Audit Committee. Messrs. Clarke, Krablin and Wright and Ms. Perelman are the members of the Audit Committee, and each is an Independent Director. Each of Messrs. Clarke, Krablin and Wright is an "audit committee financial expert" as defined in Item 407(d)(5) of Regulation S-K. The Audit Committee is responsible for the appointment, compensation, evaluation and termination of our independent registered public accounting firm, and oversees the work, internal quality-control procedures and independence of our independent registered public accounting firm. The Audit Committee discusses with management and our independent registered public accounting firm our annual audited and quarterly unaudited financial statements and recommends to the Board that our annual audited financial statements be included in our Annual Report on Form 10-K. The Audit Committee also discusses with management earnings press releases and guidance provided to analysts. The Audit Committee appoints, replaces, dismisses and, after consulting with management, approves the compensation of our outside internal audit firm. The Audit Committee also provides oversight with respect to business risk matters, compliance with ethics policies and compliance with legal and regulatory requirements. The Audit Committee has established procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, auditing and other matters and the confidential anonymous submission by employees of concerns regarding questionable accounting, auditing and other matters. The Audit Committee may obtain advice and assistance from outside legal, accounting or other advisors as it deems necessary to carry out its duties.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers, directors and beneficial owners of more than 10% of our common stock to file, by a specified date, reports of beneficial ownership and changes in beneficial ownership with the SEC and to furnish copies of such reports to us. We believe that all such filings were made on a timely basis in 2015.

Item 11 Executive Compensation

Compensation Discussion and Analysis

Set forth below is a discussion and analysis of our compensation policies and practices regarding our CEO, our CFO and the other executive officers named in the Summary Compensation Table included in this Item 11. All references to "the Committee" in this "Compensation Discussion and Analysis" section refer to our Compensation and Benefits Committee, and all references to "our NEOs" refer to the following executive officers named in the Summary Compensation Table:

- Edward B. Cloues, II, Chief Executive Officer
- H. Baird Whitehead, former President and Chief Executive Officer
- Steven A. Hartman, Senior Vice President and Chief Financial Officer
- John A. Brooks, Executive Vice President and Chief Operating Officer
- Nancy M. Snyder, Executive Vice President, Chief Administrative Officer, General Counsel and Corporate Secretary

Executive Summary

Overview of Our 2015 Performance

2015 was one of the most challenging years in the history of the oil and gas industry. The average price of oil plummeted from $59.29 per barrel in December 2014 to approximately $31.78 per barrel in January 2016, a nearly 50% decline. The price of oil has remained near these depressed levels in 2016. As a result of the precipitous decline in oil prices, our stock price, cash flow and financial position, like those of our peers, suffered as the weak industry environment completely overwhelmed our achievements during the year. In fact, a significant number of exploration and production companies have sought bankruptcy relief since the beginning of 2015, including two members of our 11-member compensation peer group.

Notwithstanding the drastic decline in oil prices, we have hedges in place that will protect our cash flow on 6,000 barrels per day of our expected 2016 oil production, and we believe that these hedges will provide approximately $100 million of cash flow, assuming February 2016 strip prices. We also accomplished several important business goals in 2015:

- We significantly improved our operational execution as the year progressed, through, among other things, implementing slickwater and high proppant completion techniques.
- We increased our historical 30-day initial production (IP) rates from an average of 664 barrels of oil per day to an average of 932 barrels of oil per day.
- We increased our historical per well EURs from 415 MBOE to 501 MBOE.
- We decreased our average drilling and completion costs from approximately $9.8 million per well at the beginning of the year to approximately $4.8 million at year end.
- We substantially decreased our drilling F&D costs per BOE (as defined below), which mitigated our increasing leverage as a result of lower prices and lower production.
- In August, we sold our East Texas oil and gas assets for $74.5 million, raising much-needed cash.

Key 2015 Compensation Decisions

The Committee approved the following 2015-related compensation for our NEOs:

- In February 2015, the Committee determined to hold NEOs' base salaries at 2014 levels for 2015.
- Based on our extremely low stock price and our financial position, in February 2016, the Committee determined not to approve any cash bonuses for our NEOs even though our cash bonus pool funded at 88%. See "2015-Related Annual Incentive Cash Bonuses" below.
- Consistent with our practice in 2014, in May 2015, the Committee approved awards of long-term equity compensation to NEOs' comprised of 45% time-based restricted stock units payable in stock, 35% performance-based restricted stock units payable in cash and 20% stock options. See "Long-Term Equity Compensation Granted in 2015" below.

Our 2015 Say-on-Pay Vote

At our 2015 Annual Meeting of Shareholders, approximately 90% of our shareholders voting on our "say-on-pay" proposal voted FOR the compensation paid to our NEOs as set forth in the "Executive Compensation" section of our 2015 Proxy Statement.

Objectives of Our Compensation Program

Our compensation program is based on the following objectives:

- *Accountability* – Executives should be held accountable for our annual performance and the achievement of our longer-term strategic goals as well as their own individual performance over both the short- and long-term. We satisfy this objective by tying compensation to the achievement of financial, strategic and operational goals based on both short- and long-term corporate and individual performance measures. See "2015-Related Annual Incentive Cash Bonuses" and "Long-Term Equity Compensation Granted in 2015" below.
- *Drive Desired Behaviors* – Our compensation program, particularly regarding incentive compensation, should be designed to drive desired behaviors consistent with our values and to achieve stated goals. We satisfy this objective by setting performance metrics for us and our executives that we believe will drive these behaviors and achieve our goals. Furthermore, while achievement of some goals, such as those related to purely financial or operational results, is easily measurable using quantitative metrics, achieving some of the other important goals we set for our executives, such as strategy- or leadership-related goals, is not. Therefore, we measure our achievement and the achievement of our executives using both quantitative and qualitative metrics. See "2015-Related Annual Incentive Cash Bonuses" below.
- *Align Interests of Executives and Shareholders* – Executive compensation should balance and align the interests of our executives with those of our shareholders by rewarding increased shareholder return. We satisfy this objective in several ways. For example, a significant portion of our executives' compensation is at risk in the form of equity or equity-based compensation, and we have made the payout levels under our NEOs' performance-based restricted stock units dependent solely upon our peer-relative TSR. In fact, this equity and equity-based compensation has seen a dramatic decrease in value in 2015. See "Long-Term Equity Compensation Granted in 2015" below.
- *Flexible Enough to Respond to Changing Circumstances*– As we saw clearly in 2015, we are in a cyclical and volatile business so we should have a flexible compensation program that is responsive to different circumstances at various points in time. To meet this objective, the Committee retains certain discretion to award higher or lower compensation than performance metrics would indicate if circumstances so warrant, and to add, delete or change the significance of compensation performance metrics during any year. For example, in February 2016, because of our extremely low stock price and our financial position, the Committee exercised discretion not to award our NEOs any annual cash incentive bonuses, even though our cash bonus pool funded at 88% of the targeted amount calculated in accordance with our Amended and Restated Annual Incentive Cash Bonus and Long-Term Equity Compensation Guidelines, or the Incentive Award Guidelines. In February 2014, in light of our 2013 144% TSR, the Committee exercised discretion to increase the bonus pool available for all of our employees by approximately five percent above the amount which the bonus pool would have been based on a purely formulaic computation contained in the Incentive Award Guidelines.
- *Industry Competitive* – Total executive compensation should be industry-competitive so that we can attract, retain and motivate talented executives with the experience and skills necessary for our success. We satisfy this objective by staying apprised, through our own research and with the assistance of the Committee's independent compensation consultant, of the amounts and types of executive compensation that our peers pay as well as general industry trends.
- *Internally Consistent and Equitable* – Executive compensation should be internally consistent and equitable. We satisfy this objective by considering not only peer benchmarks, but also our NEOs' capabilities, levels of experience, tenures, positions, responsibilities and contributions when setting their compensation.
- *Appropriate for the Employee* – The type of compensation paid to any employee should be appropriate considering the level of the employee-more senior executives should have more of their incentive compensation at risk and tied to corporate and individual performance because they are typically in a position to have a larger impact on our overall performance. For awards granted in May 2015, our NEOs' long-term equity compensation was comprised of 45% time-based restricted stock units payable in stock, 35% performance-based restricted stock units payable in cash and 20% stock options, while our vice presidents and other employees received either 100% time-based cash awards, some combination of stock options and time-based cash awards or no long-term compensation, depending on their positions.
- *Fair Protection in the Event of Change-of-Control*– We should provide fair protection to our NEOs in the event of a termination of employment associated with a change in control. See "Change-In-Control Arrangements" in this Item 11.

How Compensation Is Determined

Committee Process. The Committee generally targets the total compensation for each NEO at approximately the 50th percentile of executive officers of our peers with comparable experience, responsibilities and position within the organization. However, given the importance of executive accountability for our performance as well as for individual performance, the Committee recognizes that compensation for any NEO could exceed such 50th percentile targets, reflecting a reward for exceptional Company or individual performance, or be lower than such 50th percentile targets, reflecting Company or individual underperformance. The Committee also considers each of our NEO's level of experience in his or her current position. The performance metrics applicable to, and the Committee's rationale behind, our NEOs' 2015 compensation are described in detail below under "2015-Related Annual Incentive Cash Bonuses" and "Long-Term Equity Compensation Granted in 2015."

Because all of our NEOs other than our CEO report directly to, and work on a daily basis with, our CEO, the Committee reviews and discusses with our CEO his evaluation of the performance of each of our other NEOs and gives considerable weight to our CEO's evaluations when assessing our other NEOs' performance and determining their compensation. The Committee bases its independent evaluation of our CEO, and our CEO bases his evaluation of each of our other NEOs, primarily on whether we met or exceeded certain quantitative corporate performance metrics and whether the NEO met or exceeded certain quantitative and qualitative individual performance metrics that are specifically tailored for each NEO. Those achievement levels are considered in the context of our peer-relative TSR and any other factors the Committee deems appropriate. Our NEOs' annual incentive cash bonuses are also limited by the amount of cash in the bonus pool, which is computed annually based on our level of achievement of certain quantitative financial and operational metrics, subject to certain discretion of the Committee. See "2015-Related Annual Incentive Cash Bonuses" below for a description of the metrics used to compute the 2015 cash bonus pool.

Independent Compensation Consultant. In 2015, the Committee engaged Meridian Compensation Partners, LLC, or Meridian, as its independent compensation consultant to assist in a general review of the compensation packages for our NEOs, as well as to provide advice and information regarding the design and implementation of our executive compensation program. Meridian provided the Committee with competitive industry and general market-related analyses and trends for executive base salary, short-term incentives, long-term incentives, benefits and perquisites. The only services that Meridian provides to us are executive and director compensation consulting services to the Committee. To ensure Meridian's independence:

- The Committee directly retained and has the authority to terminate Meridian.
- Meridian reports directly to the Committee and its Chairperson.
- Meridian meets regularly in executive sessions with the Committee.
- Meridian has direct access to all members of the Committee during and between meetings.
- Interactions between Meridian and management generally are limited to data gathering and discussions regarding information which has or will be presented to the Committee.
- We paid Meridan fees in 2015 which were insignificant as a percentage of Meridian's 2015 total revenue.
- The Committee confirmed that Meridian consultants do not own any of our stock.
- Meridian confirmed that neither Meridian nor any Meridian consultant has any business or personal relationship with any of our executive officers or any Committee member.
- Meridian has in place policies and procedures that are designed to prevent conflicts of interest.

Peer Benchmarks. Set forth below is a list of the companies comprising our peer group for purposes of 2015 compensation, which is referred to as our Peer Group. The appropriate peer group was based on revenues, assets, capitalization and scope of operations. Compensation data for the Peer Group was presented to the Committee in late 2014 and was used by the Committee to help direct its compensation decisions for NEOs in early 2015. This Peer Group was also used as the performance peer group for our performance-based restricted stock units granted in May 2015.

Bill Barrett Corporation	Matador Resources Company
Carrizo Oil & Gas, Inc.	PDC Energy, Inc.
Comstock Resources Inc.	Rosetta Resources, Inc.
Exco Resources Inc.	Swift Energy Company
Laredo Petroleum Inc.	Ultra Petroleum Corp.
Magnum Hunter Resources Corporation	

Incentive Award Guidelines. The Incentive Award Guidelines provide for the establishment of an annual cash bonus pool for all employees and set forth the criteria to be used for determining the annual cash bonus and long-term equity compensation awards for our executive officers. See "2015-Related Annual Incentive Cash Bonuses" and "Long-Term Equity Compensation Granted in 2015" below.

Executive Compensation Program Composition

We pay our NEOs a base salary and provide them an opportunity to earn an annual incentive cash bonus and an annual long-term equity compensation award. The Committee's allocation of these components of compensation reflects the Committee's philosophy that a meaningful portion executive compensation should be tied to value creation as measured by our stock price and a meaningful portion should be incentive compensation which is based on annually established measurable goals.

Key features of our program include the following:

- We focus on "pay-for-performance," particularly with respect to TSR performance.
- A substantial portion of the long-term equity compensation awarded to our NEOs each year is "at risk." In fact, the equity compensation awarded to our NEOs in recent years saw a dramatic decrease in value in 2015. See "Long-Term Equity Compensation Granted in 2015" below.
- The Incentive Award Guidelines provide for a bonus pool which limits the aggregate amount of annual cash bonuses that we can pay to all employees and the size of which is determined, subject to certain discretion retained by the Committee and described under "2015-Related Annual Incentive Cash Bonuses" below, based on quantitative criteria established at the beginning of the year.
- Our NEOs do not have employment agreements.
- The Change of Control Severance Agreements for our executive officers provide for double-triggered payouts with no "tax gross ups." See "Change-in-Control Arrangements" in this Item 11.
- We do not reimburse our executive officers for any tax obligations.
- We prohibit our executive officers and other employees from engaging in any hedging activities. See "Policy Prohibiting Hedging" below.
- The differential between our CEO's total annual compensation and that of all of our other employees is appropriate. See "Internal Pay Equity at Our Company" below.
- We provide limited perquisites to our executive officers, other employees and retired executives. See "Summary Compensation Table" in this Item 11.
- We do not have a pension plan, and we do not contribute to our Supplemental Employee Retirement Plan. See "Nonqualified Deferred Compensation" in this Item 11.
- We have never repriced or replaced options, and we are prohibited from doing so by our 2013 Amended and Restated Long-Term Incentive Plan, or the Equity Plan.

Base Salaries

In February 2015, the Committee determined that, in light of depressed oil prices and general downturn of the industry which began in the fall of 2014, there would be no increase in the base salaries payable to our NEOs in 2015. Because conditions in the industry worsened substantially throughout 2015, the Committee made the same determination in February 2016. The annual base salaries paid or payable to our NEOs in 2015 and 2016 are as follows:

Name and Principal Position	Salary ($)
Edward B. Cloues, II	625,000
Chief Executive Officer	
H. Baird Whitehead	625,000
Former President and Chief Executive Officer	
Steven A. Hartman	345,000
Senior Vice President and Chief Financial Officer	
John A. Brooks	385,000
Executive Vice President and Chief Operating Officer	
Nancy M. Snyder	335,000
Executive Vice President, Chief Administrative Officer, General Counsel and Corporate Secretary	

We strive to make our NEOs' base salaries both industry-competitive and reflective of their respective capabilities, levels of experience, tenure, positions and responsibilities, as well as general economic conditions and internal pay equity. Based on data provided by Meridan in October 2014, our NEOs' base salaries were below the 50th percentile of officers in our Peer Group with comparable experience, responsibilities and position.

2015-Related Annual Incentive Cash Bonuses

The opportunity to earn an annual cash bonus creates a strong financial incentive for our NEOs to achieve or exceed a combination of near-term corporate and individual goals, which typically are set by the Committee during the first quarter of each year.

Company-Wide Cash Bonus Pool

Our NEOs' annual incentive cash bonuses are paid out of a cash bonus pool the size of which is determined based on our level of achievement, as compared to our annual budget, of several purely quantitative Company financial and operational performance metrics, which the Committee typically sets early in the year. The cash bonus pool metrics applicable to 2015 are described below under "NEO Cash Bonus Criteria-Size of the Cash Bonus Pool."

The size of the cash bonus pool is computed such that, if we meet our budget goal exactly with respect to every performance metric, the pool will fund at 100% and will be in an amount sufficient to pay all of our participating employees, including our NEOs, their target annual incentive cash bonuses, or the Target Amount. Under the Incentive Award Guidelines, in any given year, the Committee may increase or decrease the cash bonus pool by 15 percentage points if circumstances warrant. For example, if the cash bonus pool funds at 80% of the Target Amount, the Committee has the discretion to increase the pool to 95%, or decrease it to 65%, of the Target Amount. The Incentive Award Guidelines also permit the Committee to add, delete or change the relative significance of our cash bonus pool performance metrics at any time if circumstances warrant. Subject to the Committee's discretion to increase the cash bonus pool by 15 percentage points, the aggregate annual incentive cash bonuses paid to all of our employees, including our NEOs, cannot exceed the amount of the cash bonus pool. The flexibility the Committee retains with respect to the size of the cash bonus pool and the cash bonus pool performance metrics is consistent with our belief that our cyclical and volatile business requires that we have a flexible compensation program responsive to different circumstances and different requirements at various points in time. See "Compensation Philosophy" above.

NEO Cash Bonus Criteria

The cash bonus pool defines the total amount of cash available to pay annual incentive cash bonuses, but not the allocation of actual bonus awards. After the cash bonus pool has been computed, the Committee determines the actual amount of our executive officers' annual incentive cash bonuses, if any, based on the following criteria:

Size of the Cash Bonus Pool. Our 2015 cash bonus pool funded at 88% of the Target Amount based on the level of our achievement of the four 2015 cash bonus pool weighted performance metrics, which were set by the Committee in February 2015 and are shown in the chart below. The Committee chose these particular metrics because the Committee believed that these metrics would drive our near-term success and, therefore, our stock price over the long term. Meridian advised the Committee that these metrics are commonly used by our Peer Group, and by the oil and gas industry generally, to measure success.

Performance Metric	Weighting Factor	Target Performance	Actual Performance	Percent of Target Achieved	Payout Level Percent [1]
Production	25%	9,364 MBOE	7,923 MBOE	85%	0%
Drilling F&D costs per BOE [2]	25%	$32.13	$26.96	84%	200%
Cash costs per BOE [3,4]	25%	$14.98	$15.40	103%	95%
Leverage Ratio [5,6]	25%	3.88	4.55	117%	55%
Total Payout Level					88%

1 Represents the bonus pool payout percentage based on the percent of target achieved, as set forth in the Incentive Award Guidelines.

2 Drilling F&D costs per BOE is defined as (x) our cash drilling and completion capital costs related to all wells completed or identified as dry holes during the applicable year (including any capital costs incurred in any previous year related to the drilling of, or otherwise in connection with, such wells), divided by (y) our proved reserves developed as a result of such wells measured in BOE, by our independent third party engineering firm.

3 Cash costs per BOE is defined as that amount equal to (x) the sum of our cash lease operating, gathering, processing and transportation expenses, production and ad valorem taxes and general and administrative expenses as set forth in our audited 2015 financial statements minus (y) amounts accrued for cash bonus awards during 2015, divided by (z) our production during 2015 measured in BOE.

4 Excludes both equity- and liability-classified share based compensation.

5 Leverage Ratio is defined as the ratio of our Total Debt (as defined in our revolving credit facility) at December 31, 2015 to our EBITDAX for the year ended December 31, 2015.

6 EBITDAX is defined as earnings before interest, income taxes, depreciation, depletion and amortization expenses, exploration expenses, impairments and other non-cash losses or non-cash income, and excluding extraordinary gains or losses. For a reconciliation of this non-GAAP financial measure to GAAP-based measures, see Appendix A to Item 11 in this Annual Report on Form 10-K.

Our NEOs' Annual Incentive Cash Bonus Targets – The Incentive Award Guidelines provide for annual incentive cash bonus targets for our NEOs. The table below shows our NEOs' targets. According to information provided by Meridian, these targets were then comparable to the cash bonus targets used by our Peer Group for executive officers with comparable experience, responsibilities and position within the organization.

Name	2015 Target %
H. Baird Whitehead	100
Steven A. Hartman	80
John A. Brooks	90
Nancy M. Snyder	80

Individual Performance Metrics – In May 2015, the Committee approved individual performance metrics for each of our NEOs. See "Individual Performance and Determinations" below.

Peer Comparison Data – As described above under "How Compensation is Determined," the Committee targets our NEOs' total compensation to fall at approximately the 50th percentile of executive officers in our Peer Group with comparable experience, responsibilities and position within the organization. The cash bonus targets shown above are intended to result in our NEOs receiving annual cash bonuses in amounts that are competitive with our Peer Group and which constitute a reasonable and Peer Group-comparable portion of our NEOs' total compensation.

Other Criteria and Considerations – The Committee also considered our shortcomings and accomplishments in 2015 described above in "Overview of Our 2015 Performance."

Individual Performance and Determinations

The Incentive Award Guidelines require that the Committee set individual performance metrics for each NEO by June 1 of each year. In May 2015, the Committee set individual performance metrics for each of Messrs. Whitehead, Hartman and Brooks and Ms. Snyder. The individual performance metrics are a mix of quantitative and qualitative measures, individually tailored and weighted for each of the NEOs. As explained above, these individual performance metrics are used, in part, to determine the annual cash bonuses, if any, payable to our NEOs.

Because Mr. Whitehead retired prior to the end of the year, he was not eligible for a 2015-related cash bonus. Similarly, because Mr. Cloues did not assume the role of CEO until October 26, 2015, he was not eligible for a 2015-related cash bonus either.

With respect to Mr. Hartman and Ms. Snyder, the Committee set quantitative measures with a collective weight of 40% and various qualitative measures with collective weight of 60%. With respect to Mr. Brooks, the quantitative and qualitative measures were equally weighted. Mr. Hartman's quantitative measures related to our leverage ratio, cash costs per BOE and borrowing base liquidity, while Mr. Brooks' related to our production, leverage ratio, drilling F&D costs per BOE and cash costs per BOE and Ms. Snyder's related to our leverage ratio and cash costs per BOE.

Under the Incentive Award Guidelines, Messrs. Hartman and Brooks and Ms. Snyder had target cash bonus percentages of 80%, 90% and 80%, respectively, of their 2015 annual salaries. As noted above, the 2015 cash bonus pool funded at 88% of the Target Amount. The Committee believed that our NEOs generally performed well in the challenging environment in 2015. However, in light of our challenging cash and liquidity positions and extremely low stock price, the Committee felt that it was not appropriate to award any cash bonuses to our NEOs for 2015.

Long-Term Equity Compensation Granted in 2015

The opportunity to earn an annual long-term equity award aligns our NEOs with our shareholders by creating a strong financial incentive for our NEOs to promote our long-term financial and operational success and, along with our executive stock ownership guidelines, encourages NEO stock ownership. See "-Executive Stock Ownership Guidelines." Long-term equity compensation awards are expressed in dollar values at grant, and we have paid those awards in the form of performance-based restricted stock units payable in cash, time-based restricted stock units payable in shares, stock options or a combination of these awards. The actual number of performance-based restricted stock units awarded is based on a Monte Carlo simulation of potential outcomes. The actual number of time-based restricted stock units awarded is based on the NYSE closing prices of our common stock on the dates of grant. The actual number of stock options awarded is based on a weighted-average value of all options granted to our employees on the date of grant using the Black-Scholes-Merton option-pricing formula. In 2015, the Committee awarded long-term equity compensation to our NEOs comprised of 45% time-based restricted stock units payable in shares, 35% performance-based restricted stock units payable in cash and 20% stock options.

The Committee grants long-term equity incentive compensation awards to our NEOs in May of each year after our Annual Meeting of Shareholders so that it has the opportunity to consider shareholder views on any compensation-related matters that may be included in our annual Proxy Statement. Our equity awards are performance-based on both an historical basis, since the Committee considers performance during the previous year to set the grant date value of long-term equity awarded, and a forward-looking basis, since (i) the Committee also considers our NEOs' continuing services over time, (ii) awards that vest over time will increase or decrease in value depending on our future stock price and (iii) awards that are paid out based on performance measures will pay at a much lower rate if our performance during the specified performance period is below expectations and at a higher rate if our performance is above expectations.

The chart below shows the amounts of long-term equity incentive compensation awarded by the Committee to our NEOs in May 2015 as compared to their long-term equity incentive compensation targets.

Name	2014 Target %	Eligible $	Amount Paid $	% of 2014 Base Salary Paid
Edward B. Cloues, II	N/A	N/A	N/A	N/A
H. Baird Whitehead	300-600	1,875,000 - 3,750,000	2,650,000	424
Steven A. Hartman	200-400	690,000 - 1,380,000	1,300,000	377
John A. Brooks	200-400	770,000 - 1,540,000	1,000,000	260
Nancy M. Snyder	200-400	670,000 - 1,340,000	1,000,000	299

As required by the Incentive Award Guidelines, the Committee considered the following factors when awarding our NEOs the foregoing amounts of long-term equity compensation:

Our NEOs' Target Equity Compensation Percentage – As with annual cash bonus targets, our NEOs' long-term equity incentive compensation targets are intended to result in them receiving long-term equity awards that are industry-competitive. According to information provided by Meridian, our NEOs' 2015 long-term equity compensation targets were generally comparable to those of our Peer Group. See "Peer Comparison Data" below.

Individual Performance Metrics – The Committee considered whether our NEOs met their individual performance metrics, which had been approved by the Committee in February 2014. A detailed discussion of the individual performance metrics applicable to the amounts of the May 2015 equity awards was included under the heading "Individual Performance Metrics" on pages 29-32 in our 2015 Proxy Statement.

Peer Comparison Data – Based on data provided by Meridian, our NEOs' long-term equity compensation awarded in May 2015 was generally slightly below the 50th percentile of officers in our Peer Group with comparable experience, responsibilities and position.

Contribution to the Company – The Committee considered the relative importance to the success of our execution of our strategic objectives of retaining and incentivizing each NEO beyond the current year.

As a result of the dramatic decrease in our stock price, the value of the long-term equity granted to our NEOs in 2015, 2014 and 2013 has also decreased substantially. The following table shows the decrease in value of the time-based restricted stock units, performance-based restricted stock units and stock options awarded by the Committee to our NEOs (other than Mr. Cloues) in 2015, 2014 and 2013:

Name	Year	Restricted Stock Unit and Stock Option Awards		
		Aggregate Grant Date Fair Value ($) [1]	Aggregate Year-End 2015 Value ($) [2]	Percent Change %
H. Baird Whitehead	2015	2,650,003	68,648	(97.4)
	2014	2,650,011	26,638	(99.0)
	2013	2,399,996	2,439,359	1.6
Total		7,700,010	2,534,645	(67.1)
Steven A. Hartman	2015	1,300,000	33,676	(97.4)
	2014	1,100,006	11,057	(99.0)
	2013	1,099,991	1,118,023	1.6
Total		3,499,997	1,162,756	(66.8)
John A. Brooks	2015	999,998	25,905	(97.4)
	2014	1,499,998	15,078	(99.0)
	2013	1,399,994	1,422,943	1.6
Total		3,899,990	1,463,926	(62.5)
Nancy M. Snyder	2015	999,998	25,905	(97.4)
	2014	1,000,001	10,052	(99.0)
	2013	999,993	1,016,401	1.6
Total		2,999,992	1,052,358	(64.9)

1 The values of restricted stock units and stock options were computed in accordance with FASB ASC Topic 718. The values of time-based restricted stock units were based on the NYSE closing prices of our common stock on the dates of grant. The values of performance-based restricted stock units were based on a Monte Carlo simulation of potential outcomes. The values of stock options were based on the Black-Scholes-Merton option-pricing formula. All of the stock options are currently underwater.

2 The values of time-based restricted stock units were computed by multiplying the original number of restricted stock units granted by the NYSE closing price of our common stock on December 31, 2015. The values of performance-based restricted stock units were computed by multiplying the original number of restricted stock units granted by the value of such restricted stock units on December 31, 2015 based on actual performance with respect to performance periods that have ended and on a Monte Carlo simulation of potential outcomes with respect to performance periods that have not ended. The values of stock options were computed by multiplying the original number of stock options granted by the value of such stock options on December 31, 2015 based on the Black-Scholes-Merton option-pricing formula.

Compensation Risk Assessment

We believe that any risks associated with our compensation policies and practices are mitigated in large part by the following factors and, therefore, that no such risks are likely to have a material adverse effect on us:

- We pay a mix of compensation which includes near-term cash and long-term equity-based compensation.
- We base our annual incentive cash bonus and long-term equity compensation awards on several different performance metrics, which discourages our employees from placing undue emphasis on any one metric or aspect of our business at the expense of others.
- We believe that our performance metrics are reasonably challenging, yet should not require undue risk-taking to achieve.
- Our performance metrics include quantitative financial and operational metrics as well as qualitative metrics related to our operations, strategy and other aspects of our business.
- The performance periods in our new performance-based restricted stock units overlap, and our stock options and time-based restricted stock units vest over a three-year period. This mitigates the motivation to maximize performance in any one period at the expense of others.
- Our NEOs are required to own our stock as provided in our Executive Stock Ownership Guidelines.
- We believe that we have an effective management process for developing and executing our short-and long-term business plans.
- Our compensation policies and programs are overseen by the Committee.
- The Committee retains an independent compensation consultant.

Internal Pay Equity at Our Company

As discussed above, the Committee believes that comparing our NEOs' compensation to that of our peers is necessary to assess the overall competitiveness of our compensation programs. However, the Committee also believes that our compensation programs must be internally consistent and equitable.

In implementing this philosophy, the Committee discussed with our Vice President, Human Resources a study conducted by our human resources department which compared our CEO's total 2015 annual compensation to the total 2015 annual compensation of our employee whose total 2015 annual compensation fell at the median of all of our employees other than our CEO, or our Median Employee. For this purpose, total compensation was computed in the same manner as it is computed for the Summary Compensation Table. Our study demonstrated that, for 2015, our CEO's total annual compensation was approximately 28 times greater than the total annual compensation of our Median Employee. The Committee felt that these results reflected an appropriate differential in executive compensation given the wide range of responsibilities and accountability of our CEO and our other employees.

Policy Prohibiting Hedging

We believe that derivative transactions, including puts, calls and options, for our securities carry a high risk of inadvertent securities laws violations and also could afford the opportunity for our employees and directors to profit from a market view that is adverse to us. For these reasons, we prohibit our employees and directors from engaging in any type of derivative transaction in respect of our securities.

Tax Implications

Section 162(m) of the Internal Revenue Code generally precludes a publicly held company from taking a federal income tax deduction for compensation paid in excess of $1 million per year to certain covered officers. Under this section, compensation that qualifies as performance-based is excludable in determining what compensation amount qualifies for tax deductibility. Covered officers include each of our NEOs, except our CFO.

The Committee considers our ability to fully deduct compensation in accordance with the $1 million dollar limitations of Section 162(m) in structuring our compensation programs. However, the Committee retains the authority to authorize the payment of compensation that may not be deductible if it believes such payments would be in our best interests and the best interests of our shareholders.

The Committee will continue to consider ways to maximize the deductibility of executive compensation while retaining the flexibility to compensate executive officers in a manner deemed appropriate relative to their performance and to competitive compensation levels and practices at peer companies.

Compensation and Benefits Committee Report

Under the rules established by the SEC, we are required to discuss the compensation and benefits of our executive officers, including our CEO, our CFO and our other NEOs. The Compensation and Benefits Committee is furnishing the following report in fulfillment of the SEC's requirements.

The Compensation and Benefits Committee has reviewed the information contained above under the heading "Compensation Discussion and Analysis" and has discussed the Compensation Discussion and Analysis with management. Based upon its review and discussions with management, the Compensation and Benefits Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Compensation and Benefits Committee

John U. Clarke (Chairman)
Steven W. Krablin
Gary K. Wright

Summary Compensation Table

The following table sets forth the compensation paid, during or with respect to the years ended December 31, 2015, 2014 and 2013, to our CEO, our former CEO, our CFO and our two other executive officers for services rendered to us and our subsidiaries:

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) [1,2]	Option Awards ($) [3]	All Other Compensation ($) [4]	Total ($)
Edward B. Cloues, II	2015	114,726	—	79,000	—	34,150	227,876
Chief Executive Officer							
H. Baird Whitehead	2015	522,260	—	2,120,003	530,000	38,400	3,210,663
Former President and	2014	625,000	360,000	2,120,010	530,001	41,500	3,676,511
Chief Executive Officer	2013	550,000	575,000	1,919,996	480,000	41,200	3,566,196
Steven A. Hartman	2015	345,000	—	1,039,999	260,001	38,200	1,683,200
Senior Vice President and	2014	345,000	195,000	880,009	219,997	34,900	1,674,906
Chief Financial Officer	2013	325,000	270,000	879,992	219,999	36,600	1,731,591
John A. Brooks	2015	385,000	—	799,998	200,000	38,800	1,423,798
Executive Vice President and	2014	385,000	155,000	1,199,996	300,002	38,500	2,078,498
Chief Operating Officer	2013	350,000	290,000	1,119,995	279,999	213,200	2,253,194
Nancy M. Snyder	2015	335,000	—	799,998	200,000	41,800	1,376,798
Executive Vice President, Chief	2014	335,000	160,000	799,999	200,002	38,500	1,533,501
Administrative Officer, General	2013	325,000	260,000	799,995	199,998	41,200	1,626,193
Counsel and Corporate Secretary							

1 Represents the aggregate grant date fair value of time-based restricted stock units and performance-based restricted stock units granted by the C&B Committee to our NEOs in consideration for services rendered to us. These amounts were computed in accordance with FASB ASC Topic 718 and were based on the NYSE closing prices of our common stock on the dates of grant, in the case of the time-based restricted stock units, and a Monte Carlo simulation of potential outcomes, in the case of the performance-based restricted stock units. See Note 16 to our Consolidated Financial Statements included in Item 8, "Financial Statements and Supplementary Data."

2 The grant date values of the performance-based restricted stock units assuming that the highest level of performance conditions will be achieved was as follows:

Name	2015	2014	2013
Cloues	$ 0	$ 0	$ 0
Whitehead	1,515,677	1,350,806	1,146,717
Hartman	743,535	560,723	525,574
Brooks	571,946	764,592	668,915
Snyder	571,946	509,739	477,794

3 Represents the aggregate grant date fair value of stock options granted by the C&B Committee to our NEOs in consideration for services rendered to us. These amounts were computed in accordance with FASB ASC Topic 718 and were based on the Black-Scholes-Merton option-pricing formula. For a description of the assumptions used under the Black-Scholes-Merton option-pricing formula, see Note 16 to our Consolidated Financial Statements included in Item 8, "Financial Statements and Supplementary Data."

4 Reflects (i) amounts paid by us for automobile allowances and executive health exams and cash payments in lieu of the provision of health benefits and (ii) our matching and other contributions to our NEOs' 401(k) Plan accounts. The amount for Mr. Cloues includes $21,848, which is the pro-rated portion of his fourth quarter equity payment. In accordance with the terms of his compensation arrangement, such amount was paid in cash because our non-employee directors received their fourth quarter equity retainers in cash. The amount for Mr. Brooks for 2013 also includes $175,000 paid to Mr. Brooks in connection with his Employment Retention Agreement. See "Employment Retention Agreement." We contributed the following amounts to the 401(k) Plan accounts of our NEOs in 2015, 2014 and 2013:

Name	2015	2014	2013
Cloues	$ 5,769	$ 0	$ 0
Whitehead	18,400	18,100	17,800
Hartman	18,400	18,100	17,800
Brooks	18,400	18,100	17,800
Snyder	18,400	18,100	17,800

5 Mr. Cloues was elected Chief Executive Officer effective October 26, 2015. The amounts shown above for Mr. Cloues for 2015 reflect amounts paid to Mr. Cloues from and after October 26, 2015. Any compensation paid in 2015 to Mr. Cloues as a non-employee director is not included above, but is included in the Director Compensation Table included in this Item 11.

6 Mr. Whitehead resigned as President and Chief Executive Officer effective October 26, 2015, but his employment did not terminate until November 2, 2015. The amounts shown above for Mr. Whitehead for 2015 reflect amounts paid to Mr. Whitehead though November 2, 2015. Mr. Whitehead remained on the Board following his termination of employment and became entitled to receive non-employee director compensation. Any compensation paid in 2015 to Mr. Whitehead as a non-employee director is not included above, but is included in the Director Compensation Table included in this Item 11.

The cash components of our executive compensation consist of a base salary and the opportunity to earn an annual cash bonus. See “Compensation Discussion and Analysis¯Elements of Executive Compensation.” The equity component of our executive compensation program consist of the opportunity to earn awards of time-based restricted stock units, or time-based units, performance-based restricted stock units, or performance-based units, or stock options from us. See “-Narrative Discussion of Equity Awards” for a description of our time-based units, performance-based units and stock options. We have historically paid long-term equity compensation awards to our NEOs in February or May of each year, the amounts of which are based, in part, on their performance in the prior calendar year.

Grants of Plan-Based Awards

The following table sets forth the grant date and number of all performance-based units, time-based units and stock options, and the exercise price of all stock options, granted to our NEOs in 2015 by the C&B Committee, all of which were with respect to services rendered to us in 2014:

2015 Grants of Plan-Based Awards

		Estimated Future Payouts Under Equity Incentive Plan Awards [1]						
Name	**Grant Date**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**All Other Stock Awards: Number of Shares of Stock or Units [2] (#)**	**All Other Option Awards: Number of Securities Underlying Options [3] (#)**	**Exercise or Base Price of Option Awards ($/Sh)**	**Grant Date Fair Value of Stock Option Awards [4] ($)**
Edward B. Cloues, II	10/26/15				100,000			79,000
H. Baird Whitehead	5/7/15	62,839	125,678	251,356				927,504
	5/7/15				197,761			1,192,499
	5/7/15					168,270	6.03	530,000
Steven A. Hartman	5/7/15	30,827	61,653	123,306				454,999
	5/7/15				97,015			585,000
	5/7/15					82,548	6.03	260,001
John A. Brooks	5/7/15	23,713	47,425	94,850				349,997
	5/7/15				74,267			450,001
	5/7/15					63,498	6.03	200,000
Nancy M. Snyder	5/7/15	23,713	47,425	94,850				349,997
	5/7/15				74,267			450,001
	5/7/15					63,498	6.03	200,000

1 These were awards of performance-based units granted under the Equity Plan. All of these performance-based units will be settled in cash on the vesting date. See “Narrative Discussion of Equity Awards.”

2 These were awards of time-based units granted under the Equity Plan.

3 These were awards of stock options granted under the Equity Plan.

4 The grant date fair value of the performance-based units was calculated using a per share price of $7.38, which was the value of the performance-based units on the grant date using a Monte Carlo simulation of potential outcomes. The grant date fair value of the time-based units was calculated using a per share price of $0.79 in the case of Mr. Cloues and $6.01 in the case of the other NEOs, which were the NYSE closing prices of our common stock on the grant dates. The grant date fair value of the stock options was calculated using a per option value of $3.15, which was the value of the options on the grant date using the Black-Scholes-Merton option-pricing formula.

Narrative Discussion of Equity Awards

Time-Based Units

We granted time-based units to all of our NEOs (other than Mr. Cloues) in 2013, 2014 and 2015. The values of our time-based units reflected in the Summary Compensation Table and the Grants of Plan-Based Awards Table were based on the NYSE closing prices of our common stock on the dates of grant. For a discussion of the year-end 2015 actual values of these awards, see "Compensation Discussion and Analysis-Long-Term Equity Compensation Granted in 2015."

Time-based unit awards represent the right to receive shares of our common stock or an amount of cash equal to the fair market value of our shares of common stock, as determined by the C&B Committee and subject to the termination of the restriction period relating to such restricted stock units. The restriction periods for restricted stock units will terminate as determined by the C&B Committee and evidenced in an award agreement; however, restriction periods will not terminate before one year after the date of grant, except as described below. Unless otherwise determined by the C&B Committee and specified in an award agreement, if (i) a grantee ceases to be an employee for any reason other than death, disability or qualified retirement (with respect to grants prior to 2014 only), which is defined as retiring after reaching age 62 and completing 10 years of consecutive service with us or our affiliate, all unvested restricted stock units are forfeited, or (ii) a grantee dies, becomes disabled or becomes retirement eligible (with respect to grants prior to 2014 only), which is defined as reaching age 62 and completing 10 years of consecutive service with us or our affiliate, all restrictions terminate. In addition, if a change in control of us occurs, all restrictions terminate. Payments with respect to restricted stock unit awards will be made in cash, shares or any combination thereof, as determined by the C&B Committee.

Except as noted below with respect to Mr. Cloues, all time-based units ever granted to our NEOs vest over a three-year period, with one-third of each award vesting on the first, second and third anniversaries of the grant date unless forfeited or earlier vested in accordance with their terms. All time-based units ever granted to our NEOs provide that payments on such time-based units will be made in shares (or, at the request of the restricted stock unitholder and upon the approval of the C&B Committee, an amount of cash equal to the fair market value of our shares) at the time of vesting, unless vesting occurs early on account of becoming retirement eligible, in which event payments will be made when such time-based units would have originally vested, even if that is after retirement. Under the Equity Plan, no time-based unit awards may be granted with dividend equivalent rights.

Performance-Based Units

We granted performance-based units to all of our NEOs in 2013, 2014 and 2015 (except Mr. Cloues). The values of our performance-based units reflected in the Summary Compensation Table and the Grants of Plan-Based Awards Table were computed using a Monte Carlo simulation of potential outcomes. For a description of the assumptions used under our Monte Carlo simulation of potential outcomes, see Note 16 to our Consolidated Financial Statements included in Item 8, "Financial Statements and Supplementary Data." The performance-based units cliff vest on the third anniversary of the date of grant and are paid based on the relative ranking of our TSR as compared to the TSR of our Peer Group with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The performance-based units are payable solely in cash. The amount of cash payable with respect to performance-based units is equal to the sum of the payout values for each of the three performance periods. The payout value for each performance period is equal to one-third of the vested performance-based units, multiplied by the value of our common stock at the end of the applicable performance period (calculated as the average of the closing prices of our common stock on the 20 trading days immediately preceding the last day of the applicable performance period), multiplied by the applicable percentage corresponding to the relative ranking of our TSR for the applicable performance period. The applicable percentages range from 0% to 200%. The "target" percentage is 100% and corresponds to our TSR ranking in the 55th percentile of our Peer Group with respect to the 2013, 2014 and 2015 awards. The performance-based units will not have any value unless our TSR ranking is in at least the 35th percentile of our Peer Group with respect to the 2013, 2014 and 2015 awards, and our TSR ranking must be in at least the 75th percentile of our Peer Group with respect to the 2013, 2014 and 2015 awards for the performance-based units to pay out at the 200% maximum.

Except as noted below, if the grantee's employment terminates for any reason prior to the third anniversary of the grant date, then the grantee's performance-based units will be forfeited and no cash will be payable with respect to the performance-based units. With respect to grants prior to 2014 only, if the grantee is or becomes retirement eligible, and his or her employment terminates for any reason other than cause prior to third anniversary of the grant date, then all of the grantee's performance-based units will vest and become payable in the amounts and at the time that the performance-based units would have otherwise vested and been payable. If the grantee dies or becomes disabled prior to the third anniversary of the grant date, a pro-rated share (based on the number of days employed during the three-year vesting period) of the performance-based units will vest and the grantee will be paid for such performance-based units at the target percentage at the end of the original three-year vesting period. In the event of a change in control of us, all of the grantee's performance-based units will immediately vest and the grantee will be paid for such performance-based units following the change in control at the target percentage (regardless of our actual relative TSR ranking) and using the value of our common stock on the effective date of the change in control (calculated as the closing price of our common stock on the effective date of the change of control).

Stock Options

We granted stock options to all of our NEOs in 2013, 2014 and 2015 (except Mr. Cloues). The values of our stock options reflected in the Summary Compensation Table and the Grants of Plan-Based Awards Table were computed using the Black-Scholes-Merton option-pricing formula. For a description of the assumptions used under the Black-Scholes-Merton option-pricing formula, see Note 16 to our Consolidated Financial Statements included in Item 8, "Financial Statements and Supplementary Data."

The exercise price of a stock option will be greater than or equal to the NYSE closing price of our common stock on the date the stock option is awarded. Stock options will be exercisable as determined by the C&B Committee and specified in an award agreement; however, no stock option is exercisable after 10 years after the date of grant. Unless otherwise determined by the C&B Committee and specified in an award agreement, if (i) a grantee ceases to be an employee for any reason other than cause, death, disability or qualified retirement (with respect to grants prior to 2014 only), all unvested options are forfeited and all vested options immediately become exercisable and remain exercisable until the earlier of (A) 90 days after the date of such cessation or (B) the expiration date of such stock options, (ii) we terminate a grantee's employment for cause, all unexercised options are forfeited, (iii) a grantee dies or becomes disabled, all unexercised options immediately become exercisable and remain exercisable until the earlier of (A) one year after the date of death or disability or (B) the expiration date of such stock options, (iv) a grantee becomes retirement eligible (with respect to grants prior to 2014 only), all unexercised options immediately become exercisable and remain exercisable until the expiration date of such stock options, or (v) a grantee ceases to be a non-employee director, all unvested options are forfeited and all vested options immediately become exercisable and remain exercisable until the expiration date of such stock options, except in the event of the grantee's death, in which case, the options shall remain exercisable until the earlier of (A) six months after the grantee's death or (B) the expiration date of such stock options. In addition, if a change in control of us occurs, all unexercised options immediately become exercisable and remain exercisable until the expiration date of such stock options. The exercise price for a stock option must be paid in full at the time of exercise. Payment must be made in cash or, subject to the approval of the C&B Committee, in shares of our common stock valued at their fair market value, or a combination thereof. Any taxes required to be withheld must also be paid at the time of exercise. An optionee may enter into an agreement with a brokerage firm acceptable to us whereby the optionee will simultaneously exercise the stock option and sell the shares acquired thereby and the brokerage firm executing the sale will remit to us from the proceeds of sale the exercise price of the shares as to which the stock option has been exercised as well as the required amount of withholding. Stock option awards may not be granted with dividend equivalent rights.

All stock options ever granted to our NEOs have a 10-year term with an exercise price equal to the NYSE closing price of our common stock on the date the stock option is awarded. All stock options granted to our NEOs since 2004 vest over a three-year period, with one-third becoming exercisable on each of the first, second and third anniversaries of the grant date unless forfeited or earlier vested in accordance with their terms.

Timing of Grants

The C&B Committee typically grants annual compensation-related stock options, time-based units or performance-based units after our annual meeting of shareholders held in May of each year, and the timing of the C&B Committee's stock option grants to our NEOs has been historically consistent with the timing of stock option grants to other employees. The C&B Committee generally grants stock options from time to time in connection with the hiring, promotion or retention of employees, and it has in the past, and may in the future, grant time-based units or performance-based units in connection with such events. The C&B Committee may also consider grants at such other times as it may deem appropriate.

In October 2015, the C&B Committee granted 100,000 time-based units to Mr. Cloues in connection with his election as our CEO. Unlike our other time-based units, those time-based units granted to Mr. Cloues will vest 30 days after the later to occur of the date on which (i) Mr. Cloues ceases to be an employee other than as a result of termination for cause or (ii) Mr. Cloues ceases to be a director.

Dividends

We did not paid any dividends on our common stock during 2013, 2014 or 2015.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information regarding the numbers and values of unexercised stock options and time-based units and performance-based units not vested as of December 31, 2015, in each case held by our NEOs on December 31, 2015. The market value of non-vested time-based units and performance-based units is based on the NYSE closing price of our common stock on December 31, 2015.

Outstanding Equity Awards at Fiscal Year-End 2015

	Option Awards				Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Edward B. Cloues, II	0	0	N/A	N/A	100,000 [1]	30,000	0	0
H. Baird Whitehead	8,738 [2]		31.535	2/26/16	0	0	146,639 [3]	2,357,971 [4]
	10,864 [5]		35.205	2/26/17			13,795 [6]	0 [7]
	37,991 [8]		42.270	2/21/18				
	92,011 [9]		15.060	2/24/19				
	41,182 [10]		24.380	2/23/20				
	84,688 [11]		17.140	2/16/21				
	18,134 [12]		5.670	2/15/22				
	225,352 [13]		3.910	4/30/23				
	23,351 [14]		16.320	5/5/24				
Steven A. Hartman	5,086 [15]		31.535	2/26/16	166,370 [16]	49,911	67,209 [3]	1,080,721 [4]
	5,308 [5]		35.205	2/26/17			17,179 [6]	1,718 [7]
	5,845 [8]		42.270	2/21/18			61,653 [17]	9,248 [18]
	10,745 [9]		15.060	2/24/19				
	7,319 [10]		24.380	2/23/20				
	15,000 [19]		23.370	5/10/20				
	40,650 [11]		17.140	2/16/21				
	8,750 [12]		5.670	2/15/22				
	68,857 [20]	34,429 [21]	3.910	4/30/23				
	9,693 [14]	19,386 [22]	16.320	5/5/24				
		82,548 [23]	6.030	5/6/25				
John A. Brooks	5,332 [15]		31.535	2/26/16	164,940 [24]	49,482	85,539 [3]	1,375,467 [4]
	9,966 [5]		35.205	2/26/17			23,425 [6]	2,342 [7]
	15,586 [8]		42.270	2/21/18			47,425 [17]	7,114 [18]
	28,725 [25]		15.060	2/24/19				
	23,256 [10]		24.380	2/23/20				
	40,650 [11]		17.140	2/16/21				
	5,616 [12]		5.670	2/15/22				
	43,818 [26]	43,819 [21]	3.910	4/30/23				
	13,218 [14]	26,436 [22]	16.320	5/5/24				
		63,498 [23]	6.030	5/6/25				
Nancy M. Snyder	19,030 [15]		31.535	2/26/16	95,051 [27]	28,515	61,099 [3]	982,489 [4]
	19,804 [5]		35.205	2/26/17			15,617 [6]	1,562 [7]
	20,885 [8]		42.270	2/21/18			47,425 [17]	7,114 [18]
	49,596 [9]		15.060	2/24/19				
	23,619 [10]		24.380	2/23/20				
	57,588 [11]		17.140	2/16/21				
	11,270 [12]		5.670	2/15/22				
	62,597 [20]	31,299 [21]	3.910	4/30/23				
	8,812 [14]	17,624 [22]	16.320	5/5/24				
		63,498 [23]	6.030	5/6/25				

1 These restricted stock units will vest 30 days after the later to occur of the date on which (i) Mr. Cloues ceases to be an employee other than as a result of termination for cause or (ii) Mr. Cloues ceases to be a director.
2 These options vested on February 27, 2009.
3 The performance period for one-third of these performance-based units expired or will expire on each of April 30, 2014, April 30, 2015 and April 30, 2016. All of these performance-based units will vest on April 30, 2016. Because Mr. Whitehead was retirement eligible under the Equity Plan at the time of his retirement, he will vest in all of the performance-based units earned as though he had remained employed through April 30, 2016.
4 The performance period for one-third of these performance-based units expired on May 1, 2014. The payout percentage for such performance period was 200% and the payout price was $16.68. The performance period for another one-third of these performance-based units expired on May 1, 2015. The payout percentage for such performance period was 200% and the payout price was $7.14. The performance period for the final one-third of these performance-based units will expire on May 1, 2016. The market value of these performance-based units reflect (x) the actual payout value of two-thirds of these performance units and (y) an assumed payout value of one-third of these performance-based units, assuming a payout percentage of 200% and a payout price equal to the year-end 2015 price of $0.30.
5 One-third of these options vested on each of February 27, 2008, February 27, 2009 and February 27, 2010.
6 The performance period for one-third of these performance-based units expired or will expire on each of May 5, 2015, May 5, 2016 and May 5, 2017. All of these performance-based units will vest on May 5, 2017. Because Mr. Whitehead was retirement eligible under the Equity Plan at the time of his retirement, he will vest in the one-third of the performance-based units earned as though he had remained employed through May 5, 2017.
7 The performance period for one-third of these performance-based units expired on May 5, 2015. The payout percentage for such performance period was 0% and the payout price was $6.96. The performance period for another one-third of these performance-based units will expire on May 5, 2016. The performance period for the final one-third of these performance-based units will expire on May 5, 2017. The market value of these performance-based units reflect (x) the actual payout value of one-third of these performance units and (y) an assumed payout value of two-third of these performance-based units, assuming a payout percentage at the threshold level of 50% and a payout price equal to the year-end 2015 price of $0.30. With respect to Mr. Whitehead, the payout of value of his performance units is zero, which is equal to the actual payout value of one-third of the performance units.
8 One-third of these options vested on each of February 22, 2009, February 22, 2010 and February 22, 2011.
9 One-third of these options vested on each of February 25, 2010, February 25, 2011 and February 25, 2012.
10 One-third of these options vested on each of February 24, 2011, February 24, 2012 and February 24, 2013.
11 One-third of these options vested on each of February 17, 2012, February 17, 2013 and February 17, 2014.
12 These options vested on February 16, 2015.
13 These options vested on May 1, 2013.
14 These options vested May 6, 2015.
15 One-third of these options vested on each of February 27, 2007, February 27, 2008 and February 27, 2009.
16 Of these time-based units, 46,888 will vest on May 1, 2016, 11,234 will vest on May 6, 2016, 32,339 will vest on May 7, 2016, 11,233 will vest on May 6, 2017, 32,338 will vest on May 7, 2017 and 32,338 will vest on May 7, 2018.
17 The performance period for one-third of these performance-based units will expire on each of May 6, 2016, May 6, 2017 and May 6, 2018. All of these performance-based units will vest on May 6, 2018.
18 None of the performance periods for these performance-based units had expired by December 31, 2015. The market value of these performance-based units assume that all of these performance-based units payout at the threshold level of 50% at a payout price equal to the year-end 2015 price of $0.30.
19 One-third of these options vested on each of May 11, 2011, May 11, 2012 and May 11, 2013.
20 One-half of these options vested on May 1, 2014 and May 1, 2015.
21 These options will vest on May 1, 2016.
22 One-half of these options will vest on May 6, 2016 and May 6, 2017.
23 One-third of these options will vest on May 7, 2016, May 7, 2017 and May 7, 2018.
24 Of these time-based units, 59,676 will vest on May 1, 2016, 15,319 will vest on May 6, 2016, 24,876 will vest on May 7, 2016, 15,318 will vest on May 6, 2017, 24,876 will vest on May 7, 2017 and 24,875 will vest on May 7, 2018.
25 One-half of these options vested on each of February 25, 2011 and February 25, 2012.
26 These options vested on May 1, 2015.
27 Of these time-based units, 10,212 will vest on May 6, 2016, 24,876 will vest on May 7, 2016, 10,212 will vest on May 6, 2017, 24,876 will vest on May 7, 2017 and 24,875 will vest on May 7, 2018.

Stock Option Exercises and Vesting of Restricted Stock Units

The following table sets forth the number of shares of our common stock acquired, and the values realized, by our NEOs upon the exercise of stock options or the vesting of time-based units during 2015:

Option Exercises and and Stock Vested in 2015

	Option Awards		Stock Awards		
Name	Number of Shares Acquired on Exercise (#)	Realized Value on Exercise ($)	Number of Shares Acquired on Vesting (#)		Value Realized on Vesting ($)
Edward B. Cloues, II	0	0	0		0
H. Baird Whitehead	0	0	27,063	[1]	167,249
Steven A. Hartman	0	0	64,809	[2]	419,130
John A. Brooks	0	0	79,286	[3]	509,622
Nancy M. Snyder	0	0	104,076	[4]	673,622

[1] Represents shares of our common stock acquired upon vesting of time-based units:

Vesting Date	Shares (#)	Market Price ($)	Market Value ($)
May 6, 2015	27,063	6.18	167,249

[2] Represents shares of our common stock acquired upon vesting of time-based units:

Vesting Date	Shares (#)	Market Price ($)	Market Value ($)
February 16, 2015	6,687	7.14	47,745
May 1, 2015	46,888	6.44	301,959
May 6, 2015	11,234	6.18	69,426

[3] Represents shares of our common stock acquired upon vesting of time-based units:

Vesting Date	Shares (#)	Market Price ($)	Market Value ($)
February 16, 2015	4,291	7.14	30,638
May 1, 2015	59,676	6.44	384,313
May 6, 2015	15,319	6.18	94,671

[4] Represents shares of our common stock acquired upon vesting of time-based units:

Vesting Date	Shares (#)	Market Price ($)	Market Value ($)
February 16, 2015	8,612	7.14	61,940
May 1, 2015	85,251	6.44	588,232
May 6, 2015	10,213	6.18	63,116

Nonqualified Deferred Compensation

The following table sets forth certain information regarding compensation deferred by our NEOs under our Supplemental Employee Retirement Plan:

2015 Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($) [1]	Registrant Contributions in Last FY ($)	Aggregate Earnings (Loss) in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($) [2]
Edward B. Cloues, II	0	0	0	0	0
H. Baird Whitehead	0	0	(77,946)	0	2,036,723
Steven A. Hartman	0	0	0	0	0
John A. Brooks	11,994	0	(127)	0	374,421
Nancy M. Snyder	0	0	(41,364)	0	1,327,090

[1] All of these amounts are included in the amounts of salary and bonus for 2015 reported in the Summary Compensation Table.

[2] Except with respect to aggregate contributions by us of $21,906 on behalf of Mr. Whitehead in 2001 and 2002, these amounts reflect only salaries and bonuses paid to our NEOs and earnings on those salaries and bonuses. All such salary and bonus amounts were previously reported as compensation to our NEOs in the Summary Compensation Table.

The Penn Virginia Corporation Supplemental Employee Retirement Plan, or the SERP, allows all of our and our affiliates' employees whose salaries exceeded $175,000 in 2015 to defer receipt of up to 100% of their salary, net of their salary deferrals under our 401(k) Plan, and up to 100% of their annual cash bonuses. All deferrals under the SERP are credited to an account maintained by us and are invested by us, at the employee's election, in our common stock or in certain mutual funds made available by us and selected by the employee. Since all amounts deferred under the SERP consist of previously earned salary or bonus, all SERP participants are fully vested at all times in all amounts credited to their accounts. Amounts held in a participant's account will be distributed to the participant on the earlier of the date on which such participant's employment terminates or there occurs a change of control of us, unless earlier distributed in accordance with the terms of the SERP. We are not required to make any contributions to the SERP. Since we established the SERP in 1996, we have contributed an aggregate of $43,816 in 2001 and 2002 to the SERP in connection with offers of employment to Mr. Whitehead and another former executive officer, but have made no other contributions to the SERP.

We have established a rabbi trust to fund the benefits payable under the SERP. Other than the $43,816 of Company contributions described above, the assets of the rabbi trust consist of the cash amounts of salary and bonus already earned and deferred by our NEOs and other employees under the SERP and the securities in which those amounts have been invested. Assets held in the rabbi trust are designated for the payment of benefits under the SERP and are not available for our general use. However, the assets held in the rabbi trust are subject to the claims of our general creditors, and SERP participants may not be paid in the event of our insolvency.

Change-in-Control Arrangements

The C&B Committee and we believe that our senior management and other key employees are a primary reason for our success and that it is important for us to protect them in the event of certain circumstances upon a change of control. We compete for executive talent in a highly competitive market in which companies routinely offer similar benefits to senior executives. We believe that, by providing change of control protection, our executive officers will be able to evaluate objectively every Company opportunity, including a change of control, that may likely result in the termination of their employment, without the distraction of personal considerations. It allows them to focus on the negotiations during such a transaction when we would require thoughtful leadership to ensure a successful outcome. For these reasons, we have entered into change of control severance agreements with our executive officers that entitle them to the benefits described below. As noted below, our change in control severance benefits are not triggered unless employment is terminated or adversely changed in a significant manner, and we do not pay tax gross ups in the event of a change of control. We believe that the change in control severance benefits described below provide important protection to our executive officers, are consistent with the practices of our peer companies and are appropriate for the retention of executive talent.

Executive Change of Control Severance Agreements

We have entered into an Executive Change of Control Severance Agreement, referred to as an Executive Severance Agreement, with each of Messrs. Hartman and Brooks and Ms. Snyder containing the terms and conditions described below. Mr. Hartman and Ms. Snyder entered into their Executive Severance Agreements on December 20, 2012, and Mr. Brooks entered into his Executive Severance Agreement on January 29, 2013. Mr. Whitehead, our former CEO who retired in October 2015, also had an Executive Severance Agreement while he was employed by us. Mr. Cloues does not have an Executive Severance Agreement.

Term. Each Executive Severance Agreement has a two-year term, which is automatically extended for consecutive one-day periods until terminated by notice from us. If such notice is given, the Executive Severance Agreement will terminate two years after the date of such notice.

Triggering Events. Each Executive Severance Agreement provides severance benefits to the NEO upon the occurrence of two events, or the Executive Dual Triggering Events. Specifically, if a change of control of us occurs and, within two years after the date of such change of control, either (a) we terminate the NEO's employment for any reason other than for cause or the NEO's inability to perform his or her duties for at least 180 days due to mental or physical impairment or (b) the NEO terminates his or her employment due to a material reduction in his or her authority, duties, title, status or responsibility, a greater than 5% reduction in his or her base salary, a discontinuation of a material incentive compensation plan in which he or she participated, our failure to obtain an agreement from our successor to assume his or her Executive Severance Agreement or the relocation by more than 100 miles of our office at which he or she was working at the time of the change of control, then the NEO will receive the change of control severance payments and other benefits described below.

Change of Control Severance Benefits. Upon the occurrence of the Executive Dual Triggering Events, the NEO will receive a lump sum, in cash, of an amount equal to three times the sum of the NEO's annual base salary plus the highest cash bonus paid to him or her during the two-year period prior to termination, subject to reduction as described below under "Excise Taxes." In addition, all options to purchase shares of our common stock then held by the NEO will immediately vest and will remain exercisable for remainder of the options' respective terms and all other outstanding equity awards held by the NEO will immediately vest and all restrictions will lapse and we will promptly deliver any cash or stock payable thereunder. We will also provide certain health and dental benefit related payments to the NEO as well as certain outplacement services.

Excise Taxes. The Executive Severance Agreements do not include "gross up" benefits to cover excise taxes. If our independent registered public accounting firm determines that any payments to be made or benefits to be provided to the NEO under his or her Executive Severance Agreement would result in him or her being subject to the excise tax imposed by Section 4999 of the Internal Revenue Code, such payments or benefits will be reduced to the extent necessary to prevent him or her from being subject to such excise tax.

Restrictive Covenants and Releases. Each Executive Severance Agreement prohibits the NEO from (a) disclosing, either during or after his or her term of employment, confidential information regarding us or our affiliates and (b) until two years after the NEO's employment has ended, soliciting or diverting business from us or our affiliates. Each Executive Severance Agreement also requires that, upon payment of the severance benefits to the NEO, the NEO and the Company release each other from all claims relating to the NEO's employment or the termination of such employment.

Estimated Payments

The following table sets forth the estimated aggregate payments to our NEOs under their respective Executive Severance Agreements assuming that the Executive Dual Triggering Events occurred on December 31, 2015:

Name of Executive Officer	Salary and Bonus ($)	Accelerated Vesting of Restricted Stock and Units ($)	Other Benefits ($)	Total Estimated Severance Payment ($)
Edward B. Cloues, II	N/A	N/A	N/A	N/A
H. Baird Whitehead	0	0	0	0
Steven A. Hartman	1,845,000	93,723	110,049	2,048,772
John A. Brooks	2,025,000	96,399	110,049	2,231,448
Nancy M. Snyder	1,785,000	65,758	63,691	1,914,449

[1] Other benefits include medical and dental insurance-related payments and the value of outplacement services.
[2] Mr. Cloues does not have an Executive Severance Agreement.
[3] Mr. Whitehead retired effective as of November 2, 2015.

Change of Location Severance Arrangement

On December 20, 2012, we entered into an Amended and Restated Change of Location Severance Agreement, referred to as the Change of Location Agreement, with Ms. Snyder. Pursuant to the Change of Location Agreement, we agreed that, in the event of the relocation of our executive offices by more than 50 miles, Ms. Snyder may elect to receive the severance benefits described above in "Executive Change of Control Severance Agreements," except that only a pro rata portion of Ms. Snyder's equity awards will vest.

Employment Retention Agreement

On August 9, 2011, we entered into an Employment Retention Agreement, referred to as the Employment Retention Agreement, with Mr. Brooks. Pursuant to the Employment Retention Agreement, we agreed to pay Mr. Brooks $175,000 in the event that he was still employed by us on second anniversary of the Employment Retention Agreement. In August 2013, we paid Mr. Brooks $175,000 less applicable taxes in satisfaction of our obligations under the Employment Retention Agreement.

Compensation of Directors

The following table sets forth the aggregate compensation paid to our non-employee directors during 2015:

2015 Director Compensation

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($) [1]	All Other Compensation ($) [2]	Total ($)
John U. Clarke	118,000	90,000 [3]	—	208,000
Edward B. Cloues, II	147,022	90,000 [4]	5,000	242,022
Steven W. Krablin	98,000	90,000 [5]	—	188,000
Marsha R. Perelman	104,000	90,000 [6]	—	194,000
H. Baird Whitehead	28,859	— [7]	—	28,859
Gary K. Wright	118,000	90,000 [8]	600	208,600

[1] Represents the aggregate grant date fair value of shares of common stock and deferred common stock units granted to our non-employee directors. These amounts were computed in accordance with FASB ASC Topic 718 and were based on the NYSE closing prices of our common stock on the dates of grant. See Note 16 to our Consolidated Financial Statements included in Item 8, "Financial Statements and Supplementary Data."
[2] Represents amounts paid by us as matching contributions under our Matching Gifts Program, which we sponsor for our directors, officers and employees to encourage financial support of educational institutions and civic, cultural and medical or science organizations. Under the program, we will match gifts on a three-for-one basis for the first $100 given in a calendar year to an eligible charity and on a one-for-one basis for any additional contributions made to the same charity. The minimum gift which will be matched is $10. The total annual matching dollars to all charities is limited to $5,000 per director. The program is available to directors for so long as they are directors of ours. We may suspend, change, revoke or terminate the program at any time.
[3] As of December 31, 2015, Mr. Clarke had 115,506 deferred common stock units outstanding.
[4] As of December 31, 2015, Mr. Cloues had 123,471 deferred common stock units and 100,000 restricted stock units outstanding.
[5] As of December 31, 2015, Mr. Krablin had 24,644 deferred common stock units outstanding.
[6] As of December 31, 2015, Ms. Perelman had 35,202 deferred common stock units outstanding and 470 shares held in her directors' deferred compensation account.
[7] As of December 31, 2015, Mr. Whitehead had 346,777 vested but unpaid restricted stock units, 160,434 vested but unpaid performance-based restricted stock units and 542,311 options to purchase common stock outstanding.
[8] As of December 31, 2015, Mr. Wright had 148,205 deferred common stock units outstanding.

Our director compensation policy provides as follows:

In 2015, each non-employee director received an annual retainer of $180,000, consisting of $60,000 of cash and $120,000 worth of equity. Due to concerns about the dilutive effect of issuing equity at our extremely low stock price and the use of a substantial portion of our remaining available shares under the Equity Plan, the fourth quarter 2015 equity retainer ($30,000) was paid in cash. The Chairman of the Board received an additional annual cash retainer of $100,000, which was pro-rated because Mr. Cloues became Chief Executive Officer in October 2015. The Chairman of the Audit Committee received an annual cash retainer of $20,000, the Chairman of the C&B Committee received an annual cash retainer of $20,000 and the Chairman of the N&G Committee received an annual cash retainer of $6,000. All annual retainers are payable on a quarterly basis in arrears. In addition to annual retainers, each non-employee director received $2,000 cash for each in person Board meeting he or she attended (whether in person or by telephone).

Directors may elect to take their equity compensation in shares of our common stock or deferred common stock units, or a combination thereof. The actual number of deferred common stock units awarded in any given year is based upon the NYSE closing price of our common stock on the dates on which such awards are granted. Each deferred common stock unit represents one share of our common stock, which vests immediately upon issuance and is distributed to the holder upon termination or retirement from the Board.

Directors appointed during a year, or who cease to be directors during a year, receive a pro rata portion of cash and deferred common stock units. Directors, including the Chairman of the Board, may elect to receive any cash payments in common stock or deferred common stock units.

Non-Employee Director Stock Ownership Guidelines

We have stock ownership guidelines for our non-employee directors, which require our non-employee directors to own shares of our common stock having a value equal to four times the annual cash retainer payable by us for serving on the Board. As of December 31, 2015, all of our non-employee directors were in compliance with these requirements.

Non-Employee Directors Deferred Compensation Plan

Until 2011, the Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan permitted our non-employee directors to defer the receipt of any or all cash and shares of our common stock they received as compensation. All deferrals, and any distributions with respect to deferred shares of our common stock, were credited to a deferred compensation account, the cash portion of which is credited quarterly with interest calculated at the prime rate. Our non-employee directors are fully vested at all times in any cash or deferred shares of common stock credited to their deferred compensation accounts. Amounts held in a non-employee director's deferred compensation account will be distributed to the director on the January 1st following the earlier to occur of the director reaching age 70 or the retirement, resignation or removal of the director from the Board. Upon the death of a non-employee director, all amounts held in the deferred compensation account of the non-employee director will be distributed to the director's estate.

On May 4, 2011, we amended the plan to freeze it as to participation such that no future appointed non-employee directors will be eligible to participate in the plan and no existing non-employee directors will be eligible to elect further fee deferrals or share grant deferrals under the plan.

Compensation Committee Interlocks and Insider Participation

During 2015, Messrs. Clarke, Krablin and Wright served on the C&B Committee. None of these members is a former or current officer or employee of us or any of our subsidiaries or had any relationship requiring disclosure under Item 404 of Regulation S-K, "Transactions with Related Persons, Promoters and Certain Control Persons." In 2015, none of our executive officers served as a member of the board of directors or compensation committee of any entity that has one or more executive officers serving on the Board or the C&B Committee.

Appendix A

Reconciliation of GAAP "Net loss" to Non-GAAP "EBITDAX"	Year Ended December 31, 2015	2014
	(in thousands)	
Net loss from continuing operations	$ (1,582,961)	$ (409,592)
Adjustment to net loss:		
Non-consolidated net income, net of cash dividends received	—	—
Extraordinary loss (gain)	—	—
Loss (gain) on sale of assets	(41,335)	(120,769)
Loss (gain) on purchase or sale of equity	—	—
Loss on extinguishment of debt	—	—
Derivative loss (gain), net of cash settlements received (paid)	66,922	(169,636)
Loss (gain) attributable to write-ups or write-downs of assets	—	—
Cumulative pro forma effect of acquisitions and divestitures	—	—
Interest expense	90,951	88,831
Income tax benefit	(5,371)	(131,678)
Depreciation, depletion and amortization	334,479	300,299
Exploration	12,583	17,063
Impairments	1,397,424	791,809
Acquisition transaction expenses	—	—
Other non-cash expenses (share-based compensation)	4,540	3,627
Other (loss on firm transportation commitment and related accretion)	942	1,301
Less: EBITDAX of sold properties	(3,734)	—
EBITDAX	$ 274,440	$ 371,255

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

Beneficial Ownership of Common Stock

Unless otherwise indicated, the following table sets forth, as of March 1, 2016, the amount and percentage of our outstanding shares of common stock beneficially owned by (i) each person known by us to own beneficially more than 5% of our outstanding shares of common stock, (ii) each director, (iii) each executive officer named in the Summary Compensation Table under the heading "Executive Compensation¯Summary Compensation Table" and (iv) all of our directors and executive officers as a group:

Name of Beneficial Owners	Shares Beneficially Owned [1]	Percent of Class [2]
5% Holders [3]:		
Soros Fund Management LLC 888 Seventh Avenue, 33rd Floor New York, NY 10106	6,003,509	7.0%
Directors:		
John U. Clarke	247,343 [4]	—
Edward B. Cloues, II	300,103 [5]	—
Steven W. Krablin	138,248 [6]	—
Marsha R. Perelman	226,967 [7]	—
H. Baird Whitehead	718,606 [8]	—
Gary K. Wright	149,981 [9]	—
Executive Officers:		
Steven A. Hartman	273,187 [10]	—
John A. Brooks	228,086 [11]	—
Nancy M. Snyder	352,958 [12]	—
All directors and executive officers as a group (9 persons)	2,635,479 [13]	3.0%

1 Unless otherwise indicated, all shares are owned directly by the named holder and such holder has sole power to vote and dispose of such shares. Shares owned by directors and executive officers include all options that are exercisable by the named holder and all restricted stock units payable to the named holder on or prior to April 30, 2016.

2 Based on 86,347,675 shares of our common stock issued and outstanding on March 1, 2016. Unless otherwise indicated, beneficial ownership is less than 1% of our common stock.

3 All such information is based on information furnished to us by the respective shareholders or contained in filings submitted to the SEC, such as Schedules 13D and 13G.

4 Includes 115,506 deferred common stock units. See Item 11, "Executive Compensation-Compensation of Directors" for a description of a "deferred common stock unit."

5 Includes 123,471 deferred common stock units and 100,000 restricted stock units payable upon Mr. Cloues' termination of service, either as an employee or a director.

6 Includes 24,644 deferred common stock units.

7 Consists of 191,295 shares held in a trust for the benefit of Ms. Perelman, 470 shares held in Ms. Perelman's directors' deferred compensation account, and 35,202 deferred common stock units.

8 Includes options to purchase 510,222 shares and 12,870 shares held in Mr. Whitehead's deferred compensation account. Does not include 244,476 vested restricted stock units mandatorily deferred pursuant to the terms of the Equity Plan.

9 Includes 148,205 deferred common stock units.

10 Includes options to purchase 172,167 shares and 1,215 shares held in Mr. Hartman's deferred compensation account.

11 Includes options to purchase 180,835 shares and 2,326 shares held in Mr. Brooks' deferred compensation account. Does not include 94,575 vested restricted stock units mandatorily deferred pursuant to the terms of the Equity Plan.

12 Includes options to purchase 254,171 shares, 230 shares held by Ms. Snyder as custodian for a minor child, and 21,456 shares held in Ms. Snyder's deferred compensation account. Does not include 93,864 vested restricted stock units mandatorily deferred pursuant to the terms of the Equity Plan.

13 Includes options to purchase 1,117,395 shares, 470 shares held in directors' deferred compensation accounts, 447,028 deferred common stock units, 191,295 shares held in a trust for the benefit of Ms. Perelman, 230 shares held by Ms. Snyder as custodian for a minor child, and 37,867 shares held in the deferred compensation accounts of executive officers.

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2015 regarding the stock options outstanding and securities issued and to be issued under our equity compensation plans approved by the our shareholders. We do not have any equity compensation plans which were not approved by our shareholders.

Plan Category	Number of Securities To Be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by shareholders	3,083,821	16.05	2,226,571
Equity compensation plans not approved by shareholders	N/A	N/A	N/A

Item 13 Certain Relationships and Related Transactions, and Director Independence

Transactions with Related Persons

We have not entered into any transaction since January 1, 2015 requiring disclosure under Item 404 of Regulation S-K, "Transactions with Related Persons, Promoters and Certain Control Persons."

Policies and Procedures Regarding Transactions with Related Persons

Under our Corporate Governance Principles, all directors must recuse themselves from any decision affecting their personal, business or professional interests. In addition, as a general matter, our practice is that any transaction with a related person is approved by disinterested directors. Our General Counsel advises the Board as to which transactions, if any, involve related persons and which directors are prohibited from voting on a particular transaction. We have not entered into any transaction with a related person within the scope of Item 404(a) of Regulation S-K since January 1, 2015.

Director Independence

While we are no longer subject to the listing requirements of the NYSE, we continue to adhere to the independence standards of the NYSE. The N&G Committee has determined that Messrs. Clarke, Krablin and Wright and Ms. Perelman are "independent directors," as defined by NYSE Listing Standards and SEC rules and regulations. We refer to those directors as "Independent Directors." The Board has determined that none of the Independent Directors has any direct or indirect material relationship with us other than as a director of us.

Item 14 Principal Accountant Fees and Services

Audit Fees

In connection with the audits of our financial statements and internal control over financial reporting, or ICFR, for 2015, we entered into an agreement with KPMG which sets forth the terms by which KPMG will perform audit services for us. That agreement provides for alternative dispute resolution procedures. The following table shows fees for services rendered by KPMG for the audit of our consolidated financial statements for 2015 and 2014, the audit of our ICFR for 2015 and 2014 and other services rendered by KPMG:

	2015	2014
Audit Fees [1]	$ 900,743	$ 1,165,030
Audit-Related Fees [2]	—	6,000
Tax Fees	—	—
All Other Fees	—	—
Total Fees	$ 900,743	$ 1,171,030

[1] Audit fees consist of fees for the audit of our consolidated financial statements, the audit of our ICFR and consents for registration statements and comfort letters related to public offerings. Also included in audit fees are reimbursements of travel-related expenses.

[2] Audit-related fees consist of fees pertaining to debt compliance letters issued by KPMG for our revolving credit facility.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accounting Firm

The Audit Committee's policy is to pre-approve all audit, audit-related and non-audit services provided by our independent registered public accounting firm. These services may include audit services, audit-related services, tax services and other services. The Audit Committee may also pre-approve particular services on a case-by-case basis. Our independent registered public accounting firm is required to periodically report to the Audit Committee regarding the extent of services provided by our independent registered public accounting firm in accordance with such pre-approval. The Audit Committee may also delegate pre-approval authority to one or more of its members. Such member(s) must report any decisions to the Audit Committee at the next scheduled meeting. All services rendered for us by KPMG in 2015 were pre-approved by the Audit Committee.

Part IV

Item 15 Exhibit and Financial Statement Schedules

The following documents are included as exhibits to this Annual Report on Form 10-K. Those exhibits incorporated by reference are indicated as such in the parenthetical following the description. All other exhibits are included herewith.

(1)	Financial Statements — The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 53 of this Annual Report on Form 10-K.
(2.1)	Purchase and Sale Agreement, dated as of July 12, 2015, by and between Penn Virginia Oil & Gas, L.P., as seller, and Covey Park Energy LLC, as buyer (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on September 2, 2015).
(3.1)	Restated Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on July 30, 2013).
(3.1.1)	Articles of Amendment of the Restated Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on June 16, 2014).
(3.1.2)	Articles of Amendment of the Restated Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 14, 2015).
(3.2)	Amended and Restated Bylaws of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on October 29, 2015).
(4.1)	Senior Indenture dated June 15, 2009 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 16, 2009).
(4.1.1)	First Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated June 15, 2009, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).
(4.1.2)	Second Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated April 4, 2011, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2011).
(4.1.3)	Third Supplemental Indenture relating to the 7.25% Senior Notes due 2019, dated April 13, 2011, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 14, 2011).
(4.1.4)	Form of Note for 7.25% Senior Notes due 2019 (incorporated by reference to Annex A to Exhibit 4.3 to Registrant's Current Report on Form 8-K filed on April 14, 2011).
(4.1.5)	Fourth Supplemental Indenture relating to the 8.500% Senior Notes due 2020, dated April 24, 2013, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 29, 2013).
(4.1.6)	Form of 8.500% Senior Notes due 2020 (incorporated by reference to Exhibit 4.3 contained in Exhibit 1 to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 29, 2013).
(4.1.7)	Fifth Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated April 24, 2013, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6 to Registrant's Current Report on Form 8-K filed on April 29, 2013).
(4.2)	Deposit Agreement, dated October 17, 2012, among Penn Virginia Corporation, American Stock Transfer & Trust Company, LLC and the holders from time to time of the depositary shares described therein (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on October 17, 2012).
(4.2.1)	Form of depositary receipt representing the Depositary Shares (incorporated by reference to Exhibit A to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on October 17, 2012).
(4.3)	Deposit Agreement, dated June 16, 2014, among Penn Virginia Corporation, American Stock Transfer & Trust Company, LLC and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 16, 2014).
(4.3.1)	Form of depositary receipt representing the Depositary Shares (incorporated by reference to Exhibit A to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 16, 2014).
(10.1)	Credit Agreement dated as of September 28, 2012 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 2, 2012).

(10.1.1)	Waiver and First Amendment to Credit Agreement dated as of April 2, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on April 3, 2013).
(10.1.2)	Waiver and Second Amendment to Credit Agreement dated as of April 2, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on April 11, 2013).
(10.1.3)	Assignment and Third Amendment to Credit Agreement dated as of May 20, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 3, 2013).
(10.1.4)	Assignment and Fourth Amendment to Credit Agreement dated as of October 28, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 30, 2013).
(10.1.5)	Fifth Amendment and Borrowing Base Redetermination dated as of May 12, 2014 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 15, 2014).
(10.1.6)	Sixth Amendment to Credit Agreement dated as of June 16, 2014 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 16, 2014).
(10.1.7)	Seventh Amendment and Borrowing Base Redetermination dated as of October 23, 2014 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 27, 2014).
(10.1.8)	Eighth Amendment to Credit Agreement dated as of November 7, 2014 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on November 12, 2014).
(10.1.9)	Ninth Amendment and Borrowing Base Redetermination Agreement dated as of May 7, 2015 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 11, 2015).
(10.1.10)	Tenth Amendment to the Credit Agreement dated as of January 8, 2016, among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on January 11, 2016).
(10.1.11)	Eleventh Amendment to the Credit Agreement dated as of March 15, 2016, among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent. **
(10.2)	Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.2.1)	Amendment 2009-1 to the Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.4.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).*
(10.3)	Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.3.1)	Amendment One to the Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 6, 2011).*
(10.4)	Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.29 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007). *
(10.4.1)	Form of Agreement for Deferred Common Stock Unit Grants under the Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.30 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.5)	Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*
(10.5.1)	Form of Agreement for Restricted Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*

(10.5.2)	Form of Agreement for Performance Based Restricted Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Incentive Plan (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*
(10.5.3)	Form of Agreement for Stock Option Grants under the Penn Virginia Corporation Amended and Restated 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*
(10.5.4)	Form of Agreement for Deferred Common Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on July 30, 2013).*
(10.5.5)	2014 Form of Agreement for Restricted Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (incorporated by reference to to Exhibit 10.5.5 to Registrant's Annual Report on Form 10-K filed on February 25, 2015).*
(10.5.6)	2014 Form of Agreement for Performance Based Restricted Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Incentive Plan (incorporated by reference to to Exhibit 10.5.6 to Registrant's Annual Report on Form 10-K filed on February 25, 2015).*
(10.5.7)	2014 Form of Agreement for Stock Option Grants under the Penn Virginia Corporation Amended and Restated 2013 Long-Term Incentive Plan (incorporated by reference to to Exhibit 10.5.7 to Registrant's Annual Report on Form 10-K filed on February 25, 2015).*
(10.6)	Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*
(10.7)	Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Steven A. Hartman (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*
(10.8)	Executive Change of Control Severance Agreement dated January 29, 2013 between Penn Virginia Corporation and John A. Brooks (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on February 1, 2013). *
(10.9)	Amended and Restated Change of Location Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*
(10.10)	Penn Virginia Corporation Amended and Restated Annual Incentive Cash Bonus and Long-Term Equity Compensation Guidelines (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K/A filed on February 19, 2014).*
(10.11)	Purchase and Sale Agreement dated December 13, 2013, by and among Penn Virginia Oil & Gas, L.P., Ted Collins, Jr., Plein Sud Holdings, LLC, as sellers, and HPIP LaVaca, LLC, as buyer (incorporated by reference to Exhibit 10.14 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2013).
(10.12)	Amended and Restated Construction and Field Gathering Agreement dated as of September 24, 2015 by and between Penn Virginia Oil & Gas, L.P. and Republic Midstream, LLC. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the period ended September 30, 2015).
(12.1)	Statement of Computation of Ratio of Earnings to Fixed Charges and Preferred Dividends Calculation. **
(21.1)	Subsidiaries of Penn Virginia Corporation. **
(23.1)	Consent of KPMG LLP. **
(23.2)	Consent of DeGolyer and MacNaughton. **
(31.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. **
(31.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. **
(32.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. **
(32.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. **
(99.1)	Report of DeGolyer and MacNaughton dated February 3, 2016 concerning evaluation of oil and gas reserves. **
(101.INS)	XBRL Instance Document
(101.SCH)	XBRL Taxonomy Extension Schema Document

(101.CAL)	XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF)	XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB)	XBRL Taxonomy Extension Label Linkbase Document
(101.PRE)	XBRL Taxonomy Extension Presentation Linkbase Document

* Management contract or compensatory plan or arrangement.
** Filed herewith.

SIGNATURES

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

PENN VIRGINIA CORPORATION

By: /s/ STEVEN A. HARTMAN
Steven A. Hartman
Senior Vice President and Chief Financial Officer

March 15, 2016

By: /s/ JOAN C. SONNEN
Joan C. Sonnen
Vice President, Chief Accounting Officer and Controller
(Principal Accounting Officer)

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

/s/ EDWARD B. CLOUES, II **Edward B. Cloues, II**	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	March 15, 2016
/s/ JOHN U. CLARKE **John U. Clarke**	Director	March 15, 2016
/s/ STEVEN A. HARTMAN **Steven A. Hartman**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 15, 2016
/s/ STEVEN W. KRABLIN **Steven W. Krablin**	Director	March 15, 2016
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	March 15, 2016
/s/ JOAN C. SONNEN **Joan C. Sonnen**	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	March 15, 2016
/s/ H. BAIRD WHITEHEAD **H. Baird Whitehead**	Director	March 15, 2016
/s/ GARY K. WRIGHT **Gary K. Wright**	Director	March 15, 2016

Exhibit 10.1.11

ELEVENTH AMENDMENT

This Eleventh Amendment (this "Agreement") dated as of March 15, 2016 (the "Eleventh Amendment Effective Date") is among Penn Virginia Holding Corp. (the "Borrower"), Penn Virginia Corporation (the "Parent"), each subsidiary (other than the Borrower) of the Parent party hereto (together with the Parent, each, a "Guarantor" and collectively, the "Guarantors"), the Lenders (as defined below) and Wells Fargo Bank, National Association, as administrative agent (in such capacity, the "Administrative Agent") and as the issuing bank (in such capacity, the "Issuing Bank"; together with the Lenders and the Administrative Agent, the "Secured Parties").

INTRODUCTION

A. The Borrower, the Parent, the Administrative Agent, and the lenders party thereto from time to time (the "Lenders") are parties to that certain Credit Agreement dated as of September 28, 2012, (as the same has been heretofore amended, restated or otherwise modified, the "Credit Agreement").

B. The Borrower acknowledges the existence of the Subject Defaults (as defined in Schedule A attached hereto), and subject to the terms and conditions set forth herein, the parties hereto wish to provide an extension of time before the Subject Defaults would become Events of Default.

C. The parties also wish to, subject to the terms and conditions set forth herein, make certain amendments to the Credit Agreement as provided herein.

THEREFORE, in consideration of the premises and the mutual covenants, representations and warranties contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

Section 1. **Defined Terms; Other Definitional Provisions**. As used in this Agreement, each of the terms defined in the opening paragraph and the Recitals above shall have the meanings assigned to such terms therein. Each term defined in the Credit Agreement and used herein without definition shall have the meaning assigned to such term in the Credit Agreement, unless expressly provided to the contrary.

Section 2. **Amendments to Credit Agreement**.

(a) Section 1.01 (Defined Terms) of the Credit Agreement is hereby amended by revising the following terms to read as follows:

"Applicable Rate" means, for any day, with respect to any ABR Loan or Eurodollar Loan, or with respect to the Unused Commitment Fees payable hereunder, as the case may be, the applicable rate per annum set forth below under the caption "ABR Spread", "Eurodollar Spread" or "Unused Commitment Fee Rate", as the case may be, based upon the Borrowing Base Usage applicable on such date:

Borrowing Base Usage:	*ABR Spread*	*Eurodollar Spread*	*Unused Commitment Fee Rate*
Equal to or greater than 90%	*2.500%*	*3.500%*	*0.500%*
Equal to or greater than 75%, but less than 90%	*2.250%*	*3.250%*	*0.500%*
Equal to or greater than 50%, but less than 75%	*2.000%*	*3.000%*	*0.500%*
Equal to or greater than 25% but less than 50%	*1.750%*	*2.750%*	*0. 375%*
Less than 25%	*1.500%*	*2.500%*	*0.375%*

Each change in the Applicable Rate shall apply during the period commencing on the effective date of such change and ending on the date immediately preceding the effective date of the next such change.

"Borrowing Base Deficiency" means, as of any date, the amount, if any, by which the Credit Exposure on such date exceeds the lesser of (a) the Borrowing Base and (b) the aggregate Commitment Amounts, in each case, in effect on such date; provided that, for purposes of determining the existence and amount of any Borrowing Base Deficiency, obligations under any Letter of Credit will not be deemed to be outstanding to the extent such obligations are secured by cash in the manner contemplated by Section 2.06(j).

"Commitment Amount" means, with respect to each Lender, as applicable, the amount set forth opposite such Lender's name on Schedule 2.01 (including any revision thereof in accordance with Section 2.05 and any reductions thereof in accordance with this Agreement) or in the Assignment and Assumption pursuant to which such Lender shall have assumed its Commitment (or as set forth opposite such Lender's name on Schedule 2.01, plus (minus) any amounts assumed (assigned) pursuant to an Assignment and Assumption). The amount of each Lender's Commitment Amount as of the Eleventh Amendment Effective Date is set forth on Schedule 2.01.

"Default" means (a) any event or condition that constitutes an Event of Default or (b) any Immature Event of Default.

"Material Acquisition" means (i) the acquisition by the Parent or any Restricted Subsidiary of any Property (but only to the extent any net income (or loss) is attributable thereto prior to the effective date of such acquisition) or equity interests in any Person, whether in a single transaction or series of related transactions, for aggregate consideration the Fair Market Value of which exceeds the greater of $1,000,000, (ii) the redesignation in accordance with the terms of this Agreement of a Subsidiary that owns Property the Fair Market Value of which exceeds the greater of $1,000,000 as a Restricted Subsidiary or (iii) as of any date of determination, any combination of one or more acquisitions or redesignations of the types otherwise described in the foregoing clauses (i) or (ii) of this definition except that the Fair Market Value of the aggregate consideration for such acquisition or redesignation individually does not exceed $1,000,000 but for which the Fair Market Value of the aggregate consideration for all such acquisitions and redesignations during any period of twelve consecutive months ending on such date of determination exceeds $2,000,000.

"Material Disposition" means (i) the disposition by the Parent or any Restricted Subsidiary of any Property (but only to the extent any net income (or loss) is attributable thereto prior to the effective date of such disposition) or equity interests in any Person, whether in a single transaction or series of related transactions, for aggregate consideration the Fair Market Value of which exceeds the greater of $1,000,000, (ii) the redesignation in accordance with the terms of this Agreement of a Restricted Subsidiary that owns Property the Fair Market Value of which exceeds the greater of $1,000,000 as an Unrestricted Subsidiary and (iii) as of any date of determination, any combination of one or more dispositions or redesignations of the types otherwise described in the foregoing clauses (i) or (ii) of this definition except that the Fair Market Value of the aggregate consideration for such disposition or redesignation individually does not exceed $1,000,000 but for which the Fair Market Value of the aggregate consideration for all such dispositions and redesignations during any period of twelve consecutive months ending on such date of determination exceeds $2,000,000.

"Material Domestic Subsidiary" means, as of any date, any Restricted Subsidiary organized under the laws of any jurisdiction within the United States of America (including territories thereof) that (i) is a wholly-owned Restricted Subsidiary and (ii) together with its Restricted Subsidiaries, owns Property having a Fair Market Value of $500,000 or more.

"Material Indebtedness" means Indebtedness (other than the Loans and Letters of Credit) of any one or more of the Parent, the Borrower or any Restricted Subsidiary in an aggregate principal amount exceeding $10,000,000.

"Material Swap Obligations" means obligations in respect of one or more Swap Agreements of any one or more of the Parent, the Borrower or any Restricted Subsidiary in an aggregate amount exceeding $10,000,000. For purposes of determining Material Swap Obligations, the obligations of the Parent,

the Borrower or any Restricted Subsidiary in respect of any Swap Agreement at any time shall be the maximum aggregate amount (giving effect to any netting agreements) that the Parent, the Borrower or such Restricted Subsidiary would be required to pay if such Swap Agreement were terminated on the date of determination.

"Net Cash Proceeds" means, with respect to any of the transactions or events described in Sections 5.17, 6.01(j), 2.04(f), or 6.13 that results in a reduction in the Borrowing Base or the Lenders' Commitment Amounts, the positive difference, if any, of (a) the sum of cash and cash equivalents directly or indirectly received in connection with such transaction, but only as and when so received, minus (b) the sum of (i) if applicable, the principal amount of any Indebtedness that is secured by such asset (if any) and that is required to be repaid in connection with the sale thereof (other than the Loans), (ii) the reasonable out-of-pocket expenses incurred by the Parent, the Borrower or such Restricted Subsidiary in connection with such transaction.

(b) Section 1.01 (Defined Terms) of the Credit Agreement is hereby further amended by replacing the reference to "*90 days*" in the definition of "Indebtedness" with a reference to "*120 days*".

(c) Section 1.01 (Defined Terms) of the Credit Agreement is hereby further amended by adding a new defined term as follows to appear in alphabetical order therein:

"13-Week Budget" means a thirteen-week rolling operating budget and cash flow forecast, in form and substance reasonably acceptable to the Administrative Agent, which shall reflect the Borrower's good faith projection of all weekly cash receipts and disbursements in connection with the operation of the Credit Parties' and their respective Restricted Subsidiaries' business during such thirteen-week period, including but not limited to, collections, payroll, capital expenditures and other major cash outlays, as such budget and forecast may be updated from time to time as required under Section 5.02(n).

"Designated Period" means the period from the Eleventh Amendment Effective Date through and including such date thereafter when no Default exists.

"Eleventh Amendment" means that certain Eleventh Amendment dated as of the Eleventh Amendment Effective Date among the parties hereto which amends this Agreement.

"Eleventh Amendment Effective Date" means March 15, 2016.

"Immature Event of Default" means any event or condition which, upon notice, lapse of time or both would, unless cured or waived, become an Event of Default.

(d) Section 1.01 (Defined Terms) of the Credit Agreement is hereby amended by adding the following sentence to the end of the definition of "LIBO Rate":
Notwithstanding the foregoing, in any event, LIBO Rate shall not be less than 0.00% for any determination.

(e) Section 2.04 (Borrowing Base) of the Credit Agreement is hereby amended by replacing clause (b) therein in its entirety with the following:

(b) Redetermination. On or before (i) April 15th and October 15th of each year (other than April 15, 2016), and (ii) May 15, 2016, Administrative Agent shall propose in writing to the Borrower and the Lenders a new or reaffirmed Borrowing Base in accordance with Section 2.04(c) (assuming receipt by the Administrative Agent of the Reserve Report in a timely and complete manner). After having received notice of such proposal by the Administrative Agent, each Lender shall have 15 days to agree with such proposal or disagree by proposing an alternate Borrowing Base. If, at the end of such 15 days, any Lender has not communicated to the Administrative Agent its approval or disapproval, such silence shall be deemed to be an approval of the new or reaffirmed Borrowing Base proposed by the Administrative Agent. If, however, at the end of such 15-day period, all of the Lenders or the Required Lenders, as applicable, have not approved or deemed to have approved, as aforesaid, the proposed Borrowing Base, then the Borrowing Base shall be determined in accordance with Section 2.04(d). After such redetermined Borrowing Base is approved by (a) all Lenders in the case of any increase in the Borrowing Base, (b) the Required Lenders in the case of any maintenance or any decrease in the Borrowing Base or (c) as otherwise determined as provided in Section 2.04(d), the Administrative

Agent will notify the Borrower and the Lenders of the amount of the redetermined Borrowing Base, and such amount shall become effective and applicable to the Borrower, the Administrative Agent, the Issuing Bank and the Lenders (x) on or about May 1st of each year (with respect to each Reserve Report prepared as of December 31 other than the one delivered for the scheduled May 15, 2016 redetermination), (y) November 1st (with respect to each Reserve Report prepared as of June 30) of each year, and (z) June 1, 2016 for the scheduled May 15, 2016 redetermination. Notwithstanding the foregoing, however, any increase in the Borrowing Base shall require approval or deemed approval of all the Lenders as set forth in this Section 2.04(b).

(f) Section 2.04 (Borrowing Base) of the Credit Agreement is hereby amended by adding the following new clause (f) to the end thereof:

(f) <u>Periodic Reductions in the Borrowing Base - Designated Period</u>.

(A) <u>Prepayments</u>. Any and all prepayments of Loans (other than optional prepayments effected to satisfy Section 3(g) of the Eleventh Amendment but including the prepayments required to satisfy Section 5(e) of the Eleventh Amendment) and termination or expiration of unfunded Letters of Credit during the Designated Period shall result in an automatic reduction in the Borrowing Base and a pro rata reduction in the Lenders' respective Commitment Amounts, each equal to the principal amount of such prepayment or Letter of Credit, as applicable (but without duplication of any amounts required under clause (B) below).

(B) <u>Disposition</u>. If the Parent, the Borrower or any Restricted Subsidiary effects any sale, transfer or other disposition (including Casualty Events and dispositions resulting from the exercise of eminent domain, condemnation or nationalization) of Oil and Gas Properties constituting Collateral or any interest therein or all of the Equity Interests in Restricted Subsidiaries owning such Oil and Gas Properties during the Designated Period, then the Borrowing Base (and the Lenders' respective Commitment Amounts) shall automatically reduce in an amount equal to the greatest of (x) the Fair Market Value (individually or in the aggregate) thereof, (y) the Net Cash Proceeds resulting therefrom, and (z) the value, if any, assigned to such Oil and Gas Properties in the then effective Borrowing Base by the Required Lenders in good faith. To determine the amount in clause (z) above the parties agree to provide the notices required, and to follow the other procedures set forth in, the second, third, fourth and fifth sentences of Section 6.13.

(g) Section 2.11(a)(Mandatory Prepayments) of the Credit Agreement is hereby amended by replacing the reference to "Section 6.13" therein with a reference to "Section 6.13 or Section 2.04(f)(B)".

(h) Section 2.11(a)(Mandatory Prepayments) of the Credit Agreement is hereby further amended by adding the following two new sentences to the end thereof:

In addition to the foregoing, regardless of whether a Borrowing Base Deficiency exists, the Borrower shall make the prepayments required under the last sentence of Section 6.13. Furthermore and notwithstanding anything to the contrary contained herein, Parent and the Restricted Subsidiaries shall be permitted to retain up to $1,000,000 in insurance proceeds received prior to the Termination Date (as defined in the Eleventh Amendment) on account of Casualty Events that occurred prior to the Eleventh Amendment Effective Date.

(i) Section 5.01 (Financial Statements; Other Information) of the Credit Agreement is hereby amended by (i) replacing the period appearing at the end of clause (m) with a semicolon, (ii) deleting the word "*and*" at the end of clause (l), and (iii) adding the following new clauses (n) and (o) to appear at the end thereof:

(n) as soon as available and in any event on the last Business Day of each week, commencing with the first such day to occur after the Eleventh Amendment Effective Date, (i) a 13-Week Budget in form and substance reasonably acceptable to the Administrative Agent which shall reflect Borrower's good faith projection of all weekly cash receipts and disbursements in connection with the operation of the Credit Parties' and their respective Subsidiaries' business during such thirteen-week period, including but not limited to, (x) the ad valorem, severance and production taxes and lease operating expenses attributable Oil and Gas Properties and incurred for such thirteen week period (including transportation, gathering and marketing costs) and all categories of applicable expenses,

and (y) other capital expenditures, collections, payroll, and other major cash outlays, and (ii) a variance report comparing the Credit Parties' actual receipts and disbursements for such thirteen-week period with the projected receipts and disbursements for the weeks appearing in such period as reflected in the most recently delivered 13-Week Budget; and

(o) solely to the Administrative Agent, within three (3) Business Days of receiving written notice thereof by the Parent, the Borrower or any Subsidiary, copies of all Lien filings of the type described in clause (i), (ii), (iii), (iv), and (v) of the definition of "Permitted Liens" regardless of whether such Lien is a Permitted Lien (which written notice may be by electronic mail to bryan.m.mcdavid@wellsfargo.com with a copy to stephanie.song@bracewelllaw.com or such other email addresses notified to the Borrower from time to time by the Administrative Agent).

(j) Section 2.06(b) (Notice of Issuance, Amendment, Renewal, Extension; Certain Conditions) of the Credit Agreement is hereby amended by replacing the reference to "*$20,000,000*" therein with a reference to "*$1,800,000 plus any additional amounts permitted under Section 3(g) of the Eleventh Amendment*".

(k) Section 6.01 (Indebtedness) of the Credit Agreement is hereby amended by replacing clause (d) and clause (i) in their entirety with the following corresponding clause (d) and (i):

(d) Indebtedness under Capital Leases (as required to be reported on the consolidated financial statements of the Parent pursuant to GAAP) not to exceed $15,000,000; provided that, during the Designated Period, no new Capital Leases may be entered into;

(i) (x) other Indebtedness (not included under subsections (a) through (h) of this Section 6.01) not to exceed $1,000,000 in the aggregate at any one time outstanding; and (y) accounts payable incurred in the ordinary course of business that are more than 120 days past due not to exceed $1,000,000 in the aggregate at any one time outstanding;

(l) Section 6.01 (Indebtedness) of the Credit Agreement is hereby amended by adding the following new sentence to the end thereof:

Notwithstanding the foregoing, during the Designated Period, the Parent and the Borrower will not, and will not permit any Subsidiary to, create, incur or assume exist any Indebtedness otherwise permitted under clause (j) or (k) above.

(m) Section 6.02 (Liens) of the Credit Agreement is hereby amended by replacing clause (g) therein in its entirety with the following:

(g) additional Liens upon Property that does not constitute Collateral (other than cash collateral) created after the date hereof, provided that (i) the aggregate obligations secured thereby and incurred on or after the date hereof shall not exceed $1,000,000 in the aggregate at any one time outstanding, and (ii) if such Liens encumber cash collateral, the aggregate amount of cash on deposit shall not exceed $1,000,000.

(n) Section 6.04 (Investments, Loans and Advances) of the Credit Agreement is hereby amended by (i) replacing the reference to *"$10,000,000"* therein with "$*500,000*" in clause (d)(iv), and (ii) replacing clause (g) in its entirety with the following:

(g) other Investments, including Investments in Unrestricted Subsidiaries, not to exceed $500,000 in the aggregate at any time outstanding and Investments made in Penn Virginia Resources Holdings prior to the Eleventh Amendment Effective Date which were, at the time such Investments were made, permitted under this Section 6.04.

(o) Section 6.06 (Restricted Payments) of the Credit Agreement is hereby amended by replacing it in its entirety with the following:

Section 6.06 Restricted Payments. The Parent will not directly or indirectly declare or pay or incur any liability to pay, and the Parent will not permit the Borrower or any Restricted Subsidiaries to declare or pay or incur any liability to pay, directly or indirectly, any Restricted Payment, provided *that the Borrower or any Restricted Subsidiary may pay dividends or make distributions to any other Credit Party.*

(p) Section 6.10 (Designation and Conversion of Restricted and Unrestricted Subsidiaries; Indebtedness of Unrestricted Subsidiaries) of the Credit Agreement is hereby amended by adding the following to the end thereof as a new clause (e):

(e) Notwithstanding the foregoing, no Subsidiary may be designated as an Unrestricted Subsidiary under this Agreement from and after the Eleventh Amendment Effective Date.

(q) Section 6.13 (Sale of Properties) of the Credit Agreement is hereby amended by adding the following new sentence to the end thereof:

Notwithstanding the foregoing, during the Designated Period, the Parent and the Borrower will not, and will not permit any Subsidiary to, sell, assign, farm-out, convey or otherwise transfer any Property or any interest in any Property otherwise permitted under clause (d) or (e) above other than (x) the sale of Oil and Gas Properties located in Granite Wash play located in Texas and Oklahoma, whether in one transaction or in a series of related transactions ("<u>Granite Wash Sale</u>") so long as the first $8,000,000 of Net Cash Proceeds resulting from such Granite Wash Sale are applied as a mandatory prepayment of the Loans within two (2) Business Days after the consummation of such transaction(s), and (y) Casualty Events which result in the reductions provided in Section 2.04(f)(b).

(r) Section 6.14 (Environmental Matters) of the Credit Agreement is hereby amended by replacing the reference to *"$10,000,000"* found therein with a reference to *"$5,000,000, individually or in the aggregate"*.

(s) Article VI (Negative Covenants) of the Credit Agreement is hereby amended by adding the following new Section 6.24:

Section 6.24 <u>Deposit Accounts</u>. The Parent and the Borrower will not, and will not permit any Credit Party to, maintain any deposit account with any Person that is not subject to an Account Control Agreement (as defined below); provided that, the requirements of this Section 6.24 shall not apply to deposit accounts that are designated solely as accounts for, and are used solely for, (a) employee benefits, (b) taxes, (c) payroll funding, (d) cash collateral accounts to secure Pcards, Epayables or utilities the Lien on which is permitted under Section 6.02(g), or (e) petty cash, which in the case of petty cash accounts, in an amount not to exceed $250,000, in the aggregate (which petty cash account at PNC Bank, N.A. may not have originally been designated as a petty cash account). The Parent and the Borrower, for itself and on behalf of its Restricted Subsidiaries that are Credit Parties, hereby authorizes the Administrative Agent to deliver notices to the depositary banks pursuant to any Account Control Agreement under any one or more of the following circumstances: (i) following an Event of Default, (ii) if the Administrative Agent reasonably believes that a requested transfer by the Parent, the Borrower or any Restricted Subsidiary, as applicable, is a request to transfer any funds from any deposit account to any other deposit account of the Parent, the Borrower or any Restricted Subsidiary that is not permitted under this Section 6.24, (iii) as otherwise agreed to in writing by the Parent, the Borrower or any Restricted Subsidiary, as applicable, and (iv) as otherwise permitted by applicable law. "<u>Account Control Agreement</u>" shall mean, as to any deposit account of the Parent, the Borrower or any other Credit Party held with a bank, an agreement or agreements in form and substance reasonably acceptable to the Administrative Agent, among the Credit Party owning such deposit account, the Administrative Agent, and such other bank governing such deposit account.

(t) Schedule 2.01 - Commitments of the Credit Agreement is hereby replaced in its entirety with Schedule 2.01 - Commitments attached to this Agreement.

Section 3. **<u>Acknowledgment and Extension Agreement</u>**.

(a) Each Credit Party hereby acknowledges and agrees that the Existing Defaults have occurred and constitute Events of Default for all purposes under the Credit Agreement and the other Loan Documents prior to giving effect to Section 3(b) herein. Each Credit Party hereby further acknowledges and agrees that the Possible Events of Default, if they occur or had they occurred, would constitute Events of Default for all purposes under the Credit Agreement and the other Loan Documents prior to giving effect to Section 3(b) herein. After giving effect to Section 3(b), each

Credit Party hereby acknowledges and agrees that the Subject Defaults are Immature Events of Default (as defined in Section 2 above), and that such Immature Events of Default have occurred and are continuing.

(b) The Lenders hereby agree, subject to the terms of this Agreement, including the last sentence of this Section 3(b), to extend the period before such Subject Defaults become Events of Default under the Credit Agreement or any Loan Document until the date (the "Termination Date") that is the earlier to occur of (i) the Scheduled Expiration Time (as defined below), and (ii) the occurrence of any Termination Event (as defined below). For purposes hereof, "Scheduled Expiration Time" means 12:01 a.m., April 12, 2016; provided that, if prior to such scheduled time, all commodity-price Swap Agreements with Barclays Bank plc have been unwound by the applicable Credit Party and all proceeds thereof have been directed by such Credit Parties to be applied directly as prepayments on the then outstanding Loans (other than as otherwise provided in the last sentence of this Section 3(b)), then upon the application of all such proceeds, the "Scheduled Expiration Time" shall be automatically extended to 12:01 a.m., May 10, 2016 unless the Termination Date has otherwise occurred prior thereto under clause (ii) above or the representative of the Ad Hoc Committee (as defined below) notifies the Administrative Agent (which may be by electronic mail to counsel for the Administrative Agent) that the Ad Hoc Committee is not supportive of such extension. Notwithstanding the foregoing, the Termination Date for any particular Subject Default shall not be earlier than the date such Subject Default would have otherwise become an Event of Default under the Credit Agreement. If (x) the Administrative Agent has received an email from the representative of the Ad Hoc Committee reflecting the Ad Hoc Committee's support of such extension, (y) no Termination Event has occurred, and (z) the then most recently delivered 13-Week Budget delivered in compliance with Section 5.01(n) of the Credit Agreement, as amended hereby, which was reasonably acceptable to both the Administrative Agent and the Borrower reflects a need for cash to maintain adequate liquidity at the Borrower and its Restricted Subsidiaries, then up to $6,000,000 of the proceeds from the unwinding of the commodity-price Swap Agreements with Barclays Bank plc shall be directed to the Borrower to be deposited into its operating deposit account to be used for working capital purposes.

(c) The extension agreement by the Lenders described above is contingent upon the satisfaction of the conditions precedent set forth in Section 5 below and is limited to the Subject Defaults. This extension agreement is limited to the extent expressly described herein and shall not be construed to be a consent to or a waiver of the Subject Defaults or any other terms, provisions, covenants, warranties or agreements contained in the Credit Agreement or in any of the other Loan Documents (other than, for the avoidance of doubt, the extension of such time period as provided above before the Subject Defaults become Events of Default). The Secured Parties reserve (i) the right to exercise any rights and remedies available to them in accordance with the Loan Documents or applicable law in connection with such Subject Defaults on and after the Termination Date and (ii) the right to exercise any rights and remedies available to them in accordance with the Loan Documents or applicable law in connection with any other present or future Default with respect to the Credit Agreement or any other provision of any Loan Document.

(d) Each Credit Party hereby further agrees and acknowledges that (i) the Subject Defaults have not been waived as a result of this Agreement and that such extension agreement is temporary in nature, and (ii) from and after the Termination Date, all Subject Defaults shall become Events of Default (unless otherwise provided under the Loan Documents).

(e) Any of the following shall constitute a "Termination Event" under this Agreement:

(i) the failure of any Credit Party to comply with any covenant or agreement contained in this Agreement;

(ii) any representation or warranty contained in this Agreement was incorrect or misleading in any material respect;

(iii) the exercise by any one or more creditors or holders of Indebtedness of any Credit Party in an aggregate principal amount in excess of $1,000,000 of any right or remedy available to them in connection with any default under the documents governing such Indebtedness resulting in, or giving such creditor or holder the right to initiate, (A) any foreclosure or enforcement action against any Collateral or (B) acceleration of such Indebtedness;

(iv) the commencement of any bankruptcy, reorganization, debt arrangement or other case or proceeding under any applicable bankruptcy or insolvency law or any dissolution, winding up or liquidation proceeding with respect to any Credit Party (regardless of whether commenced by the Borrower, any other Credit Party or any other Person);

(v) any Credit Party repudiates or asserts a defense in writing to any obligation or liability under this Agreement, the Credit Agreement or any other Loan Document or makes or pursues a claim in writing against the Administrative Agent, the Issuing Bank or any Lender in connection with this Agreement, the Credit Agreement or any other Loan Document;

(vi) the occurrence or existence of any Event of Default (other than the Subject Defaults); and

(vii) the Administrative Agent determines, in its sole and absolute discretion, that any one or more of the following circumstances exists: (A) any of the Parent, the Borrower or any Restricted Subsidiary is not negotiating in good faith with the Administrative Agent, the Lenders or certain holders of the Unsecured Notes, on the terms of a mutually acceptable potential debtor-in-possession financing by one or more of the Lenders (a "Potential DIP"), a full conversion of all outstanding Unsecured Notes to Equity Interests of the Parent (the "Full Conversion"), and a full monetization of all commodity-price Swap Agreements of the Parent, the Borrower or any Restricted Subsidiary (it being understood that the application of such proceeds (other than as required and agreed to under Section 5(e) and Section 3(f) below) are being considered by all parties involved) (the "Full Monetization"), in each case, in connection with an orderly pre-arranged or pre-packaged bankruptcy filing on or prior to May 15, 2016, (B) an ad hoc committee of holders of the Unsecured Notes holding at least 50% of the then outstanding Unsecured Notes (the "Ad Hoc Commitee") are not negotiating in good faith with the Administrative Agent and the Lenders on the Potential DIP, the Full Conversion, and Full Monetization, in each case, in connection with an orderly pre-arranged or pre-packaged bankruptcy filing on or prior to May 15, 2016, or (C) any of the Parent, the Borrower or Restricted Subsidiary threatens in writing to recharacterize, avoid, void, subordinate or attack in any manner any Obligation or any Lien created or purported to be created under the Collateral Documents or claim that the Administrative Agent has a Lien on less than 100% of the total value of the Parent's, the Borrower's and the Restricted Subsidiaries' Oil and Gas Properties attributable to "proved reserves" (as defined in the Definitions for Oil and Gas Reserves as promulgated by the Society of Petroleum Engineers (or any generally recognized successor) as in effect from time to time); provided, however, none of the above clauses (vii)(A) through (vii)(C) shall be a Termination Event until five (5) Business Days after prior written notice of the Administrative Agent's determination thereof is delivered by the Administrative Agent to the Borrower, Attn: Nancy Snyder (nancy.snyder@pennvirginia.com) and Steve Hartman (steve.hartman@pennvirginia.com) (with a copy to: Kirkland & Ellis LLP, Attn: Brian Schartz (bschartz@kirkland.com) and Mary Kogut (mkogut@kirkland.com)).

The Borrower acknowledges and agrees that the written notice provided for in clause (vii) above may be delivered by electronic mail to the e-mail addresses noted above and agrees to accept such electronic mail as written notice.

(f) On each date that any of the Credit Party's commodity-price Swap Agreements (i) settles on its scheduled payment dates or (ii) is unwound, terminated or liquidated, in each case, from the date hereof until May 10, 2016, the Borrower shall, unless otherwise agreed to by the Majority Lenders, prepay the then outstanding Loans in an amount equal to the settlement, unwinding, termination or liquidation payments, as applicable, received on such trade or transaction and such prepayment shall be effected by the applicable Credit Party directing the proceeds thereof to be applied as a prepayment of then outstanding Loans. To accommodate the foregoing requirement, each Credit Party hereby authorizes each Lender and each of its Affiliates, from time to time until the earlier of the Termination Date and May 10, 2016, to the fullest extent permitted by law, to set off and apply any and all obligations at any time owing by such Lender or Affiliate to or for the credit or the account of such Credit Party against any of and all the obligations of any other Credit Party now or hereafter existing under this clause (f), irrespective of whether or not such Lender shall have made any demand under this Agreement. The rights of each Lender under this clause (f) are in addition to other rights and remedies (including other rights of setoff) that such Lender may have.

(g) Notwithstanding the terms set forth in Section 4.02 of the Credit Agreement, the Lenders and the Borrower hereby agree that (i) the Issuing Bank shall issue one or more Letters of Credit on account of any Credit Party from the date hereof and until the Termination Date so long as (x) the aggregate principal amount of such Letters of Credit issued prior to the Termination Date does not exceed $750,000, (y) on or prior to the issuance of such Letter of Credit, the Borrower shall have made one or more optional prepayments of the outstanding Loans (other than, for the avoidance of doubt any mandatory prepayments of the outstanding Loans, including under clause (f) above) in an aggregate principal amount at least equal to the aggregate principal amount of all Letters of Credit issued since the date hereof (including the then requested Letter of Credit), and (z) all other terms and conditions required under the Credit Agreement for the issuance of such Letter of Credits shall have been met other than (A) that the Borrower is unable to make the representation and warranty under Section 3.24 of the Credit Agreement or the last two sentences of Section 3.07, and (B) that the Subject Defaults to the extent they are Immature Events of Default (as defined in Section 2 above) may have occurred and are continuing, and (ii) the Issuing Bank shall cause the currently outstanding Letter of Credit in favor of the Railroad Commission of Texas to auto-renew for another one year term on or about April 1, 2016 in accordance with the terms thereof so long as all terms and conditions required under the Credit Agreement to permit such auto-renewal shall have been met other than (x) that the Borrower is unable to make the representation and warranty under Section 3.24 of the Credit Agreement or the last two sentences of Section 3.07, and (y) that the Subject Defaults to the extent they are Immature Events of Default may have occurred and are continuing.

(h) Notwithstanding the terms set forth in Section 4.02 or Section 2.13(c) of the Credit Agreement, the Lenders acknowledge and agree that, until the Termination Date, (i) the Lenders shall not elect to charge the default rate of interest as permitted under Section 2.13(c)(ii) of the Credit Agreement, and (ii) solely as to a Borrowing which consists solely of the conversion or continuation of an outstanding Loan from one Type of Loan into another Type of Loan, the Borrower shall be permitted to continue and convert such Borrowing so long as all terms and conditions required under the Credit Agreement for such continuation or conversion shall have been met other than (A) that the Borrower is unable to make the representation and warranty under Section 3.24 of the Credit Agreement or the last two sentences of Section 3.07, and (B) that the Subject Defaults to the extent they are Immature Events of Default (as defined in Section 2 above) may have occurred and are continuing.

(i) In addition to the Borrower's obligation to pay the expenses pursuant to Section 9.03 of the Credit Agreement, Borrower agrees to remit to Bracewell LLP, as counsel for the Administrative Agent, a retainer in the amount of $250,000 on April 11, 2016, which amount (A) need not be held by Bracewell LLP in a separate bank account, (B) may be applied as payment of, or credit to, legal expenses of the Administrative Agent or any other Lender, and (C) is in addition to the retainer amount set forth in Section 5(b) below.

Section 4. **Representations and Warranties.** Each Credit Party hereby represents and warrants that: (a) the representations and warranties contained in the Credit Agreement, as amended hereby, and after giving effect to any amendments to the schedules thereto set forth herein, and the representations and warranties contained in the other Loan Documents, as amended hereby, and after giving effect to any amendments to the schedules thereto set forth herein, are true and correct in all material respects on and as of the Eleventh Amendment Effective Date (i) except to the extent that any such representation or warranty expressly relates solely to an earlier date, in which case such representation or warranty was true and correct in all material respects as of such earlier date (except that such materiality qualifiers shall not be applicable to the extent any representations and warranties are already qualified or modified by materiality in the text thereof) and (ii) other than the representation or warranty in the last sentence of Section 3.07 and in Section 3.24 of the Credit Agreement, which the Borrower acknowledges that it is unable to make; (b) no Default has occurred and is continuing other than the Subject Defaults; (c) the execution, delivery and performance of this Agreement are within the corporate and limited liability company power and authority of such Credit Party, as applicable, and have been duly authorized by appropriate corporate and limited liability company action and proceedings, as applicable; (d) this Agreement constitutes the legal, valid, and binding obligation of such Credit Party, enforceable in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law; (e) there are no governmental or other third party consents, licenses and approvals required in connection with the execution, delivery, performance, validity and enforceability of this Agreement; (f) the Collateral is unimpaired by this Agreement and the Credit Parties have granted to the Administrative Agent, a valid, binding, perfected, enforceable, first priority (subject to Permitted Liens) Liens in the Collateral covered by the Collateral Documents, including the deposit accounts that are the subject of the control agreements required under Section 5(c) below; and (g) such Liens are not subject to avoidance, subordination, recharacterization, recovery, attack, offset, counterclaim, or defense of any kind (the "Subject Claims"); provided that, the Credit Parties are not making a representation or warranty under this clause (g) that no creditor (including an unsecured creditors committee) of the Parent, Borrower or Restricted Subsidiaries would bring Subject Claims in a bankruptcy proceeding.

Section 5. **Conditions to Effectiveness.** This Agreement shall become effective on the Eleventh Amendment Effective Date and enforceable against the parties hereto and the other Lenders pursuant to the terms of the Credit Agreement upon the occurrence of the following conditions:

(a) The Administrative Agent shall have received counterparts of this Agreement duly executed by the Parent, the Borrower, the other Guarantors and the Majority Lenders;

(b) The Borrower shall have paid all fees and expenses of the Administrative Agent's outside legal counsel and other consultants and of the legal counsels for the Lenders in the steering committee , in each case, pursuant to all invoices presented for payment on or prior to the Eleventh Amendment Effective Date, which the Borrower acknowledges and agrees may include a retainer amount up to $250,000, which amount need not be held by Bracewell LLP in a separate bank account and may be applied as payment of, or credit to, legal expenses of the Administrative Agent or any other Lender;

(c) The Borrower shall have delivered fully executed Account Control Agreements (as defined in Section 2 above) with respect to all deposit accounts maintained by the Borrower, the Parent or any other Credit Party, subject to the exceptions set forth in Section 2 above;

(d) The Administrative Agent shall have received fully executed, true and complete copies of non-disclosure agreements binding the Ad Hoc Committee in form and substance satisfactory to the Administrative Agent (which satisfaction is evidenced by the delivery of the Administrative Agent's signature hereto); and

(e) All existing commodity-price Swap Agreements with Wells Fargo Bank, National Association and with Société Générale shall have been unwound and 100% of the proceeds thereof shall have been directed by the Borrower to be applied as a prepayment of outstanding Loans.

Section 6. **Acknowledgments and Agreements.**

(a) Each Credit Party acknowledges that on the date hereof all outstanding Obligations are payable in accordance with their terms and each Credit Party waives any defense, offset, counterclaim or recoupment, in each case existing on the date hereof, with respect to such Obligations.

(b) The descriptions herein of the Subject Defaults are based upon the information provided to the Lenders on or prior to the date hereof and shall not be deemed to exclude the existence of any other Defaults or Events of Default. The failure of the Lenders to give notice to the Borrower or the Guarantors of any such other Defaults or Events of Default is not intended to be nor shall be a waiver thereof. **Each Credit Party hereby agrees and acknowledges that the Secured Parties require and will require strict performance by the Credit Parties of all of their respective obligations, agreements and covenants contained in the Credit Agreement and the other Loan Documents (including any action or circumstance which is prohibited or limited during the existence of a Default or Event of Default), and no inaction or action by any Secured Party regarding any Default or Event of Default (including but not limited to the Subject Defaults) is intended to be or shall be a waiver thereof. Each Credit Party hereby also agrees and acknowledges that no course of dealing and no delay in exercising any right, power, or remedy conferred to any Secured Party in the Credit Agreement or in any other Loan Documents or now or hereafter existing at law, in equity, by statute, or otherwise shall operate as a waiver of or otherwise prejudice any such right, power, or remedy (collectively, the "Lender Rights").**

(c) Furthermore, each party hereto hereby agrees that, in no event and under no circumstance shall any past or future discussions with the Administrative Agent or any other Secured Party, serve to (i) cause a modification of the Loan Documents, (ii) establish a custom or course of dealing with respect to any of the Loan Documents, (iii) operate as a waiver of any existing or future Default or Event of Default under the Loan Documents, (iv) entitle any Credit Party to any other or further notice or demand whatsoever beyond those required by the Loan Documents, or (v) in any way modify, change, impair, affect, diminish or release any Credit Party's obligations or liability under the Loan Documents or any other liability any Credit Party may have to the Administrative Agent, the Issuing Bank, or any other Secured Party.

(d) For the avoidance of doubt, each Credit Party hereby also agrees and acknowledges that the extension provided under Section 3 above shall not operate as a waiver of or otherwise prejudice any of the Lender Rights as to the Subject Defaults or otherwise (other than the extension of time provided under Section 3 as to Subject Defaults). The Administrative Agent, the Issuing Bank and the Lenders hereby expressly reserve all of their rights, remedies, and claims under the Loan Documents except as expressly limited in Section 3 above. Nothing in this Agreement shall constitute a waiver or relinquishment of (i) any Default or Event of Default (including, without limitation, any Subject Default) under any of the Loan Documents, (ii) any of the agreements, terms or conditions contained in any of the Loan Documents, (iii) any rights or remedies of any Secured Party with respect to the Loan Documents (except as expressly limited in Section 3 above), or (iv) the rights of any Secured Party to collect the full amounts owing to them under the Loan Documents. For the avoidance of doubt and other than as permitted under Section 3(g) above, the Lenders have no obligation to make additional Loans and the Issuing Lender has no obligation to issue, extend or amend any Letters of Credit until all Defaults (including the Subject Defaults) have been waived in writing by the Majority Lenders (it being understood that none of the Lenders is obligated to grant any such waiver) and all other conditions as required under the Credit Agreement have been met.

(e) Each Credit Party, the Administrative Agent, the Issuing Bank and each Lender does hereby adopt, ratify, and confirm the Credit Agreement, as amended hereby, and acknowledges and agrees that the Credit Agreement, as amended hereby, is and remains in full force and effect, and the Credit Parties acknowledge and agree that their respective liabilities and obligations under the Credit Agreement, as amended hereby, the other Loan Documents, and the Guaranty, are not impaired in any respect by this Agreement.

(f) This Agreement is a Loan Document for the purposes of the provisions of the other Loan Documents. Without limiting the foregoing, any breach of representations, warranties, and covenants under this Agreement shall be a Default or Event of Default, as applicable, under the Credit Agreement.

Section 7. **Reaffirmation of the Guaranty**. Each Credit Party hereby ratifies, confirms, acknowledges and agrees that its obligations under the Guaranty are in full force and effect and that such Credit Party continues to unconditionally and irrevocably guarantee the full and punctual payment, when due, whether at stated maturity or earlier by acceleration or otherwise, all of the Guaranteed Obligations (as defined in the Guaranty), as such Guaranteed Obligations may have been amended, extended and increased by this Agreement, and its execution and delivery of this Agreement does not indicate or establish an approval or consent requirement by such Credit Party under the Guaranty in connection with the execution and delivery of amendments, consents or waivers to the Credit Agreement, the Notes or any of the other Loan Documents.

Section 8. **Release**. **For good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, each Credit Party hereby, for itself and its successors and assigns, fully and without reserve, releases, acquits, and forever discharges each Secured Party, its respective successors and assigns, officers, directors, employees, representatives, trustees, attorneys, agents and affiliates (collectively the "Released Parties" and individually a "Released Party") from any and all actions, claims, demands, causes of action, judgments, executions, suits, debts, liabilities, costs, damages, expenses or other obligations of any kind and nature whatsoever, direct and/or indirect, at law or in equity, whether now existing or hereafter asserted, whether absolute or contingent, whether due or to become due, whether disputed or undisputed, whether known or unknown (INCLUDING, WITHOUT LIMITATION, ANY OFFSETS, REDUCTIONS, REBATEMENT, CLAIMS OF USURY OR CLAIMS WITH RESPECT TO THE NEGLIGENCE OF ANY RELEASED PARTY) (collectively, the "Released Claims"), for or because of any matters or things occurring, existing or actions done, omitted to be done, or suffered to be done by any of the Released Parties, in each case, on or prior to the Eleventh Amendment Effective Date and are in any way directly or indirectly arising out of or in any way connected to any of this Agreement, the Credit Agreement, any other Loan Document, or any of the transactions contemplated hereby or thereby (collectively, the "Released Matters"). Each Credit Party, by execution hereof, hereby acknowledges and agrees that the agreements in this Section 8 are intended to cover and be in full satisfaction for all or any alleged injuries or damages arising in connection with the Released Matters herein compromised and settled. Each Credit Party hereby further agrees that it will not sue any Released Party on the basis of any Released Claim released, remised and discharged by the Credit Parties pursuant to this Section 8. In entering into this Agreement, each Credit Party consulted with, and has been represented by, legal counsel and expressly disclaim any reliance on any representations, acts or omissions by any of the Released Parties and hereby agrees and acknowledges that the validity and effectiveness of the releases set forth herein do not depend in any way on any such representations, acts and/or omissions or the accuracy, completeness or validity hereof. The provisions of this Section 8 shall survive the termination of this Agreement, the Credit Agreement and the other Loan Documents and payment in full of the Obligations.**

Section 9. **Financial Advisor**. The Administrative Agent has retained, through its counsel or otherwise, a financial advisor (such financial advisor, or any successor or replacement thereof, the "Financial Advisor"). In consideration of the agreements given herein, the Parent and the Borrower each acknowledge and agree that the Parent and the Borrower shall, and shall cause each of their respective Subsidiaries to, cooperate in all reasonable respects with the Financial Advisor and shall promptly provide to the Financial Advisor such information regarding the operations, business affairs, assets and financial condition of the Parent, the Borrower and their respective Subsidiaries as reasonably requested by the Financial Advisor. In addition, the Parent and the Borrowers shall, and shall cause each of their respective Subsidiaries to, permit the Financial Advisor to discuss such operations, business affairs, assets and financial condition with the officers and directors of the Parent, the Borrower, and their respective Subsidiaries and shall make such officers and directors available to the Financial Advisor for such purpose as may be reasonably requested and during normal business hours. The Borrower acknowledges that it is required to pay all reasonable and documented out-of pocket costs and expenses of the Financial Advisor in accordance with Section 9.03(a) of the Credit Agreement.

Section 10. **Counterparts.** This Agreement may be executed in counterparts (and by different parties hereto on different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. Delivery of an executed counterpart of a signature page of this Agreement by telecopy shall be effective as delivery of a manually executed counterpart of this Agreement.

Section 11. **Successors and Assigns.** This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted pursuant to the Credit Agreement.

Section 12. **Incorporation by Reference**. Sections 1.03, 9.03(a), 9.07, 9.09, 9.10, 9.11, 9.15 of the Credit Agreement are incorporated herein, *mutatis mutandis*.

Section 13. NO ORAL AGREEMENTS. THE RIGHTS AND OBLIGATIONS OF EACH OF THE PARTIES TO THE LOAN DOCUMENTS SHALL BE DETERMINED SOLELY FROM WRITTEN AGREEMENTS, DOCUMENTS AND INSTRUMENTS, AND ANY PRIOR ORAL AGREEMENTS BETWEEN SUCH PARTIES ARE SUPERSEDED BY AND MERGED INTO SUCH WRITINGS. THIS AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER WRITTEN LOAN DOCUMENTS EXECUTED BY PARENT, BORROWER, ANY OTHER CREDIT PARTY, THE ADMINISTRATIVE AGENT, ANY ISSUING BANK AND/OR LENDERS REPRESENT THE FINAL AGREEMENT REGARDING THE MATTERS HEREIN BETWEEN SUCH PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR SUBSEQUENT ORAL AGREEMENTS BY SUCH PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN SUCH PARTIES.

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EXECUTED to be effective as of the date first above written.

BORROWER:

PENN VIRGINIA HOLDING CORP.

By: /s/ Nancy Snyder
Name: Nancy Snyder
Title: Executive Vice President

PARENT:

PENN VIRGINIA CORPORATION

By: /s/ Nancy Snyder
Name: Nancy Snyder
Title: Executive Vice President

GUARANTORS:

PENN VIRGINIA OIL & GAS CORPORATION
PENN VIRGINIA OIL & GAS GP LLC
PENN VIRGINIA OIL & GAS LP LLC
PENN VIRGINIA MC CORPORATION
PENN VIRGINIA MC ENERGY L.L.C.
PENN VIRGINIA MC OPERATING COMPANY L.L.C.

Each By:/s/ Nancy Snyder
Name: Nancy Snyder
Title: Executive Vice President

PENN VIRGINIA OIL & GAS, L.P.

By: Penn Virginia Oil & Gas GP LLC, its general partner

By: /s/ Nancy Snyder
Name: Nancy Snyder
Title: Executive Vice President

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent, Issuing Bank and a Lender

By: /s/ Bryan M. McDavid
Name: Bryan M. McDavid
Title: Director

ROYAL BANK OF CANADA,
as a Lender

By: /s/ Mark Lumpkin, Jr.
Name: Mark Lumpkin, Jr.
Title: Authorized Signatory

BANK OF AMERICA, N.A.,
as a Lender

By: /s/ Kenneth Phelan
Name: Kenneth Phelan
Title: Director

SCOTIABANC INC.,
as a Lender

By: /s/ J.F. Todd
Name: J.F. Todd
Title: Managing Director

CREDIT SUISSE AG, Cayman Islands Branch,
as a Lender

By:
Name:
Title:

By:
Name:
Title:

BRANCH BANKING AND TRUST COMPANY,
as a Lender

By: /s/ James Giordano
Name: James Giordano
Title: Senior Vice President

BARCLAYS BANK, PLC,
as a Lender

By: /s/ Vanessa A. Kurbatskiy
Name: Vanessa A. Kurbatskiy
Title: Vice President

Comerica BANK,
as a Lender

By:
Name:
Title:

SOCIÉTÉ GÉNÉRALE,
as a Lender

By:
Name:
Title:

CAPITAL ONE, NATIONAL ASSOCIATION,
as a Lender

By:
Name:
Title:

SUNTRUST BANK,
as a Lender

By: /s/ William S. Krueger
Name: William S. Krueger
Title: First Vice President

SANTANDER BANK, N.A.,
as a Lender

By:
Name:
Title:

By:
Name:
Title:

Schedule A

Subject Defaults

1. The Borrower was unable to comply with the current ratio requirement under Section 6.09(b) of the Credit Agreement as of the fiscal quarter ended December 31, 2015 and may be unable to comply with the current ratio requirement under Section 6.09(b) of the Credit Agreement as of the fiscal quarter ending March 31, 2016;

2. The Borrower may be unable to comply with the total leverage ratio requirement under Section 6.09(a) of the Credit Agreement as of the fiscal quarter ending March 31, 2016;

3. With its audited financial statements for the fiscal year ended December 31, 2015, the accompanying opinion of the independent public account would contain a "going concern" qualification which would be prohibited under Section 5.01(a) of the Credit Agreement;

4. An Event of Default under Section 7.01(j) of the Credit Agreement as a result of the Parent, the Borrower or any Restricted Subsidiary being unable to or failing generally to pay its debt as they become due.

5. The Borrower and its Restricted Subsidiaries have permitted certain operators', vendors', carriers', warehousemen's, repairmen's, mechanics', suppliers', workers', materialmen's, construction or other like Liens arising by operation of law in the ordinary course of business or incident to the exploration, development, operation and maintenance of Oil and Gas Properties or statutory landlord's liens, including lessee or operator obligations under statutes, governmental regulations or instruments related to the ownership, exploration and production of oil, gas and minerals on private, state, federal or foreign lands or waters, to exists in respect of obligations that outstanding more than 60 days and that are not being contested in good faith by appropriate proceedings or for which adequate reserves have not been maintained in accordance with GAAP, which are not permitted under Section 6.02 of the Credit Agreement.

6. The Borrower and its Restricted Subsidiaries have permitted the Liens of the type described in clause (vi) of the definition of "Permitted Liens" (but for the fact such Liens secure amounts that may be delinquent or may not be contested in good faith by appropriate proceedings and for which adequate reserves have not been maintained in accordance with GAAP) to exists in favor of Hunt Oil Company and its affiliates, which are not permitted under Section 6.02 of the Credit Agreement.

7. Parent and its Restricted Subsidiaries may fail to make scheduled interest payments on the Unsecured Notes.

8. The Borrower has not promptly provided, and as to any of the foregoing that may occur prior to the Termination Date, may not be able to promptly provide, written notice of the foregoing occurrence which is required under Section 5.02(a) of the Credit Agreement.

Each of the foregoing is referred to as a "Subject Default" and collectively, the "Subject Defaults". Each of the Defaults described in #1, #5, #6 and, to the extent related to any of the foregoing, #7, is referred to as "Existing Default" and collectively, the "Existing Defaults". All Subject Defaults other than Existing Defaults are referred to as "Possible Events of Default". For the avoidance of doubt, the Subject Default under item #4 above does not include any Default that may arise under any other clause of Section 7.01, including as a result of any failure to pay amounts due and payable under the Loan Documents or any Material Indebtedness.

Schedule 2.01

COMMITMENT AMOUNTS

Lender	Commitment Amount	Applicable Percentage
Wells Fargo Bank, National Association	$25,340,500.00	14.750000000%
Royal Bank of Canada	$25,340,500.00	14.750000000%
Bank of America, N.A.	$17,609,500.00	10.250000000%
Scotiabanc Inc.	$17,609,500.00	10.250000000%
Credit Suisse AG, Cayman Islands Branch	$15,032,500.00	8.750000000%
Branch Banking and Trust Company	$10,737,500.00	6.250000000%
Barclays Bank PLC	$10,737,500.00	6.250000000%
Comerica Bank	$10,737,500.00	6.250000000%
Société Générale	$10,737,500.00	6.250000000%
Capital One, National Association	$10,737,500.00	6.250000000%
SunTrust Bank	$8,590,000.00	5.000000000%
Santander Bank, N.A.	$8,590,000.00	5.000000000%
Total:	**$171,800,000.00**	**100.000000000%**

Exhibit 12.1

Penn Virginia Corporation and Subsidiaries
Statement of Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends
(in thousands, except ratios)

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Earnings:					
Income (loss) from continuing operations before income taxes	$ (1,588,332)	$ (541,270)	$ (220,766)	$ (173,291)	$ (221,070)
Fixed charges	122,505	121,608	97,903	66,616	62,002
Capitalized interest	(6,288)	(7,232)	(5,266)	(803)	(1,983)
Preferred stock dividend requirements	(22,866)	(22,661)	(10,647)	(2,793)	—
	$ (1,494,981)	$ (449,555)	$ (138,776)	$ (110,271)	$ (161,051)
Fixed charges:					
Interest expense	$ 90,951	$ 88,831	$ 78,841	$ 59,339	$ 56,216
Capitalized interest	6,288	7,232	5,266	803	1,983
Rent factor	2,400	2,884	3,149	3,681	3,803
Preferred stock dividend requirements	22,866	22,661	10,647	2,793	—
	$ 122,505	$ 121,608	$ 97,903	$ 66,616	$ 62,002
Ratio of earnings to fixed charges and preferred stock dividends [1]	—	—	—	—	—

[1] During 2015, 2014, 2013, 2012, and 2011, earnings were deficient by $1,617,486, $571,163, $236,679, $176,887 and $223,053, respectively, regarding the coverage of fixed charges and preferred stock dividends.

Exhibit 21.1

Subsidiaries of Penn Virginia Corporation

Name	Jurisdiction of Organization
Penn Virginia Holding Corp.	Delaware
Penn Virginia Oil & Gas Corporation	Virginia
Penn Virginia Oil & Gas, L.P.	Texas
Penn Virginia Oil & Gas GP LLC	Delaware
Penn Virginia Oil & Gas LP LLC	Delaware
Penn Virginia MC Corporation	Delaware
Penn Virginia MC Energy L.L.C.	Delaware
Penn Virginia MC Operating Company L.L.C	Delaware
Penn Virginia MC Gathering Company L.L.C.	Oklahoma
Penn Virginia Resource Holdings Corp.	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Penn Virginia Corporation:

We consent to the incorporation by reference in the registration statement on Form S-3 (No. 333-204160) and on Form S-8 (No. 33-59647, 333-82304, 333-96463, 333-96465, 333-82274, 333-103455, 333-143514, 333-159304, 333-173990 and 333-188587) of Penn Virginia Corporation of our reports dated March 15, 2016, with respect to the consolidated balance sheets of Penn Virginia Corporation as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, shareholders' equity, cash flows, and for each of the years in the three-year period ended December 31, 2015, and the effectiveness of internal control over financial reporting as of December 31, 2015, which reports appear in the December 31, 2015 annual report on Form 10-K of Penn Virginia Corporation.

Our report dated March 15, 2016 contains an explanatory paragraph that states that the Company has suffered recurring losses from operations and is dependent on obtaining additional financing to continue its planned principal business operations. These factors raise substantial doubt about its ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of that uncertainty.

/s/ KPMG LLP

Houston, Texas
March 15, 2016

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 15, 2016

Penn Virginia Corporation
840 Gessner, Suite 800
Houston, Texas 77024

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our "Report as of December 31, 2015 on Reserves and Revenue owned by Penn Virginia Corporation" (our Report) in Part I and in the "Notes to Consolidated Financial Statements" portions of the Annual Report on Form 10-K of Penn Virginia Corporation for the year ended December 31, 2015 (the Annual Report). In addition, we hereby consent to the incorporation by reference of our letter report dated February 3, 2016 in the "Exhibits and Financial Statement Schedules" portion of the Annual Report. We further consent to the incorporation by reference of references to DeGolyer and MacNaughton and to our Report in Penn Virginia Corporation's Registration Statements on Form S-3 (File No. 333-204160) and Form S-8 (File No. 33-59647, File No. 333-82304, File No. 333-96463, File No. 333-82274, File No. 333-103455, File No. 333-143514, File No. 333-159304, File No., 333-173990, and File No. 333-188587).

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

Exhibit 31.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Edward B. Cloues, II, Chairman of the Board and Chief Executive Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: March 15, 2016

/s/ EDWARD B. CLOUES, II

Edward B. Cloues, II
Chairman of the Board and Chief Executive Officer

Exhibit 31.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: March 15, 2016

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Edward B Cloues, II, Chairman of the Board and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2016

/s/ EDWARD B. CLOUES, II

Edward B. Cloues, II
Chairman of the Board and Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn Virginia Corporation (the “Company”) on Form 10-K for the year ended December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2016

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 3, 2016

Penn Virginia Corporation
840 Gessner
Suite 800
Houston, Texas 77024

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved oil and condensate, natural gas liquids (NGL), and gas reserves, as of December 31, 2015, of certain selected properties in which Penn Virginia Corporation (Penn Virginia) has represented that it owns an interest. This evaluation was completed on February 3, 2016. Penn Virginia has represented that these properties account for 100 percent of Penn Virginia's net proved reserves as of December 31, 2015. The properties evaluated herein are located in Oklahoma, Pennsylvania, and Texas. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by Penn Virginia.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2015. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Penn Virginia after deducting all interests owned by others.

Estimates of oil and condensate, NGL, and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such 8 estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with Penn Virginia personnel, from Penn Virginia files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Penn Virginia with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Penn Virginia, and the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as that portion of the total gas to be delivered into a gas pipeline for sale after separation, processing, fuel use, and flare. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit and at the legal pressure base of the state in which the reserves are located. Gas quantities included herein are expressed in thousands of cubic feet (Mcf). Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to processing agreements. Oil and condensate and NGL reserves included in this report are expressed in terms of barrels (bbl) representing 42 United States gallons per barrel.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves - Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves - Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4-10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The development status shown herein represents the status applicable on December 31, 2015. In the preparation of this study, data available from wells drilled on the evaluated properties through December 31, 2015, were used in estimating gross ultimate recovery. When applicable, gross production estimated through December 31, 2015, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves as of December 31, 2015. In some fields this required that the production rates be estimated for up to 2 months, since production data from certain properties were available only through October 2015.

Our estimates of Penn Virginia’s net proved reserves attributable to the reviewed properties are based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2015			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved				
Developed Producing	19,616	6,125	36,798	31,874
Developed Nonproducing	573	77	374	712
Undeveloped	9,273	1,002	4,981	11,105
Total Proved	**29,462**	**7,204**	**42,153**	**43,691**

Note: Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth of future net revenue. Future gross revenue is defined as that revenue to be realized from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating, gathering, processing expenses, capital costs, and abandonment costs from the future gross revenue. Present worth of future net revenue is calculated by discounting the future net revenue at the arbitrary rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Revenue values in this report were estimated using the initial prices and expenses provided by Penn Virginia. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The assumptions used for estimating future prices and expenses are as follows:

Oil and Condensate and NGL Prices

Oil and condensate and NGL prices were calculated using specified differentials for each lease supplied by Penn Virginia to a price of $50.28 per barrel and held constant thereafter. The West Texas Intermediate Cushing price of $50.28 per barrel is the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to December 31, 2015. The volume-weighted average price was $45.78 per barrel for oil and condensate and $13.15 per barrel for NGL.

Gas Prices

Gas prices were calculated using specified differentials for each lease supplied by Penn Virginia to a Henry Hub price of $2.59 per million British thermal units (MMBtu) and held constant thereafter. The Henry Hub gas price of $2.59 per MMBtu is the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to December 31, 2015. British thermal unit factors provided by Penn Virginia were used to convert prices from $/MMBtu to dollars per thousand cubic feet. The volume-weighted average price was $2.701 per thousand cubic feet.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for each state in which the reserves are located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Penn Virginia based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Operating expenses and capital costs, provided by Penn Virginia and based on current costs, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. Abandonment costs were provided by Penn Virginia and were not adjusted for inflation.

The estimated future revenue attributable to the production and sale of Penn Virginia's net proved reserves of the properties evaluated, as of December 31, 2015, is summarized in thousands of dollars (M$) as follows:

	Proved			
	Developed Producing (M$)	**Developed Nonproducing (M$)**	**Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	1,073,033	28,462	455,751	1,557,246
Production and Ad Valorem Taxes	83,361	2,177	34,704	120,242
Operating Expenses	468,608	8,722	134,379	611,709
Capital and Abandonment Costs	16,497	6,714	183,405	206,616
Future Net Revenue	504,567	10,849	103,263	618,679
Present Worth at 10 Percent	325,637	4,273	(6,599)	323,311

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2015, estimated oil and gas reserves.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil and condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries - Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4-10(a) (1)-(32) of Regulation S-X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S-K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Penn Virginia. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Penn Virginia. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

DeGOLYER and MacNAUGHTON Texas

Registered Engineering Firm F-716

/s/ Gregory K. Graves, P. E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Penn Virginia dated February 3, 2016, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 31 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton