Vanguard Natural Resources, LLC
Form 10-K
March 02, 2015

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

FORM 10-K
(Mark One)

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

Or

p TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .

Commission File Number 001-33756

Vanguard Natural Resources, LLC
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	61-1521161 (I.R.S. Employer Identification No.)
5847 San Felipe, Suite 3000 Houston, Texas (Address of Principal Executive Offices)	77057 (Zip Code)

Telephone Number: (832) 327-2255
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Units	The NASDAQ Global Select Market
7.875% Series A Cumulative Redeemable Perpetual Preferred Units	The NASDAQ Global Select Market
7.625% Series B Cumulative Redeemable Perpetual Preferred Units	The NASDAQ Global Select Market
7.75% Series C Cumulative Redeemable Perpetual Preferred Units	The NASDAQ Global Select Market

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 x No o

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

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

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

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

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

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

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

The aggregate market value of Vanguard Natural Resources, LLC common units held by non-affiliates of the registrant as of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $2,599,585,338 based upon the closing price reported for such date on the NASDAQ Global Select Market.

As of February 25, 2015, 83,709,271 of the registrant's common units remained outstanding.

Documents Incorporated by Reference:
Portions of the registrant's proxy statement to be furnished to unitholders in connection with its 2015 Annual Meeting of Unitholders are incorporated by reference in Part III— Items 10-14 of this annual report on Form 10-K for the year ending December 31, 2014 (this "Annual Report"). Such proxy statement will be filed with the Securities and Exchange Commission within 120 days of the registrant's fiscal year ended December 31, 2014.

Vanguard Natural Resources, LLC

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Forward-Looking Statements

Certain statements and information in this Annual Report may constitute "forward-looking statements." The words "may," "will," estimate," "predict," "potential," "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "woul similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors and other factors that could cause our actual results to differ from those in our forward-looking statements are those described in "Item 1A. Risk Factors" and those described elsewhere in this Annual Report. Factors that could affect our actual results and could cause actual results to differ materially from those in our forward-looking statements include, but are not limited to, the following:

- the volatility of realized oil, natural gas and NGLs prices, including the recent declines in such prices;
- the potential for additional impairment due to continuing or future declines in oil, natural gas and NGLs prices;
- uncertainties about the estimated quantities of oil, natural gas and NGLs reserves, including uncertainties about the effects of the SEC's rules governing reserve reporting;
- the conditions of the capital markets, liquidity, general economic conditions, interest rates and the availability of credit to support our business requirements;
- the discovery, estimation, development and replacement of oil, natural gas and NGLs reserves;
- our business and financial strategy;
- our future operating results;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our operating expenses, general and administrative costs, and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our prospect development and property acquisitions;
- the marketing of oil, natural gas and NGLs;
- competition in the oil, natural gas and NGLs industry;
- the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, earthquakes and other catastrophic events and natural disasters;
- governmental regulation of the oil, natural gas and NGLs industry;
- environmental regulations;
- the effect of legislation, regulatory initiatives and litigation related to climate change;
- developments in oil-producing and natural gas-producing countries; and
- our strategic plans, objectives, expectations and intentions for future operations.

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

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

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

Below is a list of terms that are common to our industry and used throughout this document:

/day	= per day	Mcf	= thousand cubic feet
Bbls	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
Bcf	= billion cubic feet	MMBbls	= million barrels
Bcfe	= billion cubic feet equivalents	MMBOE	= million barrels of oil equivalent
BOE	= barrel of oil equivalent	MMBtu	= million British thermal units
Btu	= British thermal unit	MMcf	= million cubic feet
MBbls	= thousand barrels	MMcfe	= million cubic feet equivalent
MBOE	= thousand barrels of oil equivalent	NGLs	= natural gas liquids

When we refer to oil, natural gas and NGLs in “equivalents,” we are doing so to compare quantities of natural gas with quantities of oil and NGLs or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which 42 gallons is equal to one Bbl of oil or one Bbl of NGLs and one Bbl of oil or one Bbl of NGLs is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

References in this report to “us,” “we,” “our,” the “Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC (“VNG”), VNR Holdings, LLC (“VNRH”), Vanguard Permian, LLC (“Vanguard Permian”), Vanguard Operating, LLC (“VO”), VNR Finance Corp. (“VNRF”), Encore Energy Partners Operating LLC (“OLLC”) and Encore Clear Fork Pipeline LLC. References in this report to “our operating subsidiary” or “VNG” are to Vanguard Natural Gas, LLC.

PART I

ITEM 1. BUSINESS

Overview

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increase our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, as of December 31, 2014, we own properties and oil and natural gas reserves primarily located in nine operating basins:

- the Green River Basin in Wyoming;
- the Piceance Basin in Colorado;
- the Permian Basin in West Texas and New Mexico;
- the Gulf Coast Basin in Texas, Louisiana and Mississippi;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Williston Basin in North Dakota and Montana;
- the Wind River Basin in Wyoming; and
- the Powder River Basin in Wyoming.

We were formed in October 2006 and completed our initial public offering in October 2007. Our common units are listed on the NASDAQ Global Select Market (“NASDAQ”), an exchange of the NASDAQ OMX Group Inc. (Nasdaq: NDAQ), under the symbol “VNR.” Our Series A, Series B and Series C Cumulative Preferred units are also listed on the NASDAQ under the symbols “VNRAP”, “VNRBP” and “VNRCP,” respectively.

Organizational Structure

The following diagram depicts our organizational structure as of March 2, 2015:

Recent Developments

Acquisitions of Oil and Natural Gas Properties

Pinedale Acquisition

On January 31, 2014, we completed the acquisition of natural gas and oil properties in the Pinedale and Jonah fields of Southwestern Wyoming for approximately $555.6 million in cash with an effective date of October 1, 2013. The purchase price was funded with borrowings under our Reserve-Based Credit Facility (defined in Note 3 of the Notes to the Consolidated Financial Statements included in Part II-Item 8. Financial Statements and Supplementary Data). As of December 31, 2014, based on internal reserve estimates, the interest acquired had estimated total net proved reserves of 705.8 MMcfe, of which 85% was natural gas reserves and 48% was proved developed producing.

Piceance Acquisition

On September 30, 2014, we completed the acquisition of natural gas, oil and NGLs assets in the Piceance Basin in Colorado for approximately $502.1 million in cash. Through this acquisition, we acquired additional interests in the same properties previously acquired in the Rockies Acquisition completed in December 2012. The purchase price was funded with borrowings under our Reserve-Based Credit Facility and is subject to additional customary post-closing adjustments to be determined based on an effective date of July 1, 2014. As of December 31, 2014, based on internal reserve estimates, the interest acquired had estimated total net proved reserves of 336.5 MMcfe, of which 78% was natural gas reserves and 71% was proved developed producing.

Other Acquisitions

On May 1, 2014, we completed an asset exchange transaction with Marathon Oil Company in which we acquired natural gas and NGLs properties in the Wamsutter natural gas field in Wyoming in exchange for 75% of our working interests in the Gooseberry Field properties in Wyoming. The total consideration for this transaction was the mutual exchange and assignment of interests in the properties and net cash consideration of $6.8 million paid to Marathon Oil Company. The cash consideration was funded with borrowings under our Reserve-Based Credit Facility. This transaction had an effective date of January 1, 2014.

On August 29, 2014, we completed the acquisition of certain natural gas, oil and NGLs properties located in North Louisiana and East Texas for an adjusted purchase price of $269.9 million, subject to additional customary post-closing adjustments to be determined based on an effective date of June 1, 2014.

During the year ended December 31, 2014, we completed other smaller acquisitions of certain natural gas, oil and NGLs properties located in the Permian Basin and Powder River Basin in Wyoming for an aggregate purchase price of $17.7 million.

Equity Offerings

On March 11, 2014, we completed a public offering of 7,000,000 7.625% Series B Cumulative Preferred Units at a price of $25.00 per unit. Offers were made pursuant to a prospectus supplement to our Shelf Registration Statement (discussed in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations”). We received proceeds of approximately $169.3 million from this offering, after deducting underwriting discounts of $5.5 million and offering costs of $0.2 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

On September 15, 2014, we completed a public offering of 4,000,000 7.75% Series C Cumulative Preferred Units at a price of $25.00 per unit. Offers were made pursuant to a prospectus supplement to our Shelf Registration Statement. We received proceeds of approximately $96.9 million from this offering, after deducting underwriting discounts of $3.2 million and offering costs of $0.2 million. On September 23, 2014, we received additional proceeds of approximately $7.3 million from the sale of an additional 300,000 Series C Cumulative Preferred Units that were purchased pursuant to the underwriters’ over-allotment option. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

During the year ended December 31, 2014, total net proceeds received under our at-the-market equity program were approximately $147.8 million, after commissions and fees, from the sales of 4,863,690 common units and $1.2 million, after commissions and fees, from the sales of 45,946 Series A Cumulative Preferred Units.

Proved Reserves

Our total estimated proved reserves at December 31, 2014 were 2,031.3 Bcfe, of which approximately 15% were oil reserves, 73% were natural gas reserves and 12% were NGLs reserves. Of these total estimated proved reserves, approximately 68% were classified as proved developed. At December 31, 2014, estimated future cash inflows from estimated future production of proved reserves were computed using the average oil, natural gas and NGLs price based upon the 12-month average price of $94.87 per barrel of crude oil, $4.36 per MMBtu for natural gas, and $35.35 per barrel of NGLs.

At December 31, 2014, we owned working interests in 9,759 gross (3,664 net) productive wells. Our operated wells accounted for approximately 53% of our total estimated proved reserves at December 31, 2014. Our average net daily production for the year ended December 31, 2014 was 327,109 Mcfe/day. Our average proved reserves-to-production ratio, or average reserve life, is approximately 14 years based on our total proved reserves as of December 31, 2014 and our fourth quarter 2014 annualized production.

Additionally, we own approximately 870,140 gross undeveloped leasehold acres surrounding our existing wells. As of December 31, 2014, we have identified 1,254 proved undeveloped drilling locations and over 3,931 other drilling locations on our leasehold acreage.

Business Strategies

Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders, and over the long-term to increase the amount of our future distributions by executing the following business strategies:

- Manage our oil and natural gas assets with a focus on maintaining cash flow levels;

- Replace reserves and/or production either through the development of our extensive inventory of proved undeveloped locations or make accretive acquisitions of oil and natural gas properties in the known producing basins of the continental United States characterized by a high percentage of producing reserves, long-life, stable production and step-out development opportunities;

- Maintain a capital structure which affords financial flexibility for opportunistic acquisitions; and

- Use hedging strategies to reduce the volatility in our revenues resulting from changes in oil, natural gas and NGLs prices.

Properties

As of December 31, 2014, through certain of our subsidiaries, we own interests in oil and natural gas properties located in nine operating basins. The following table presents the production for the year ended December 31, 2014 and the estimated proved reserves for each operating area:

	2014 Net Production					
	Natural Gas	Oil	NGLs	Total	Net Estimated Proved Reserves	PV10 Value
	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcfe)	(in millions)
Green River Basin	30,793	306	1,216	39,921	764,877	$828.0
Piceance Basin	12,349	105	519	16,094	441,673	$515.2
Permian Basin	6,363	1,046	477	15,504	241,286	$488.5
Gulf Coast Basin	2,598	358	152	5,654	181,509	$419.6
Big Horn Basin	229	1,003	92	6,799	104,437	$360.3
Arkoma Basin	18,577	21	235	20,113	211,503	$203.9
Williston Basin	157	441	6	2,843	25,097	$89.5
Wind River Basin	3,295	21	62	3,791	36,842	$48.7
Powder River Basin	8,676	—	—	8,676	24,111	$22.0

The following is a description of our properties by operating basin:

Green River Basin Properties

Our Green River Basin properties are comprised of assets in the Pinedale and Jonah Fields of southwestern Wyoming. Production in the Green River Basin is dominated by natural gas and NGLs from tight sands formations. The Pinedale Field lies at depths anywhere between 8,000 to 14,000 feet with similar depths in the adjacent Jonah Field. As of December 31, 2014, our Green River Basin properties consisted of 126,420 gross (35,038 net) leasehold acres. During 2014, the Green River Basin properties produced approximately 39,921 MMcfe of which 77% was natural gas. At December 31, 2014, the properties had total proved reserves of approximately 764,877 MMcfe or 38% of our total estimated proved reserves at year end, of which 52% were proved developed and 84% were natural gas.

Piceance Basin Properties

The Piceance Basin is located in northwestern Colorado. Our Piceance Basin properties, which we operate, are located in the Gibson Gulch. The Gibson Gulch area is a basin-centered gas play along the north end of the Divide Creek anticline near the eastern limits of the Piceance Basin's productive Mesaverde (Williams Fork) trend at depths of approximately 7,500 feet. As of December 31, 2014, our Piceance Basin properties consisted of 24,040 gross (16,075 net) leasehold acres. During 2014, our properties in the Piceance Basin produced approximately 16,094 MMcfe, of which 77% was natural gas. At December 31, 2014, the Piceance Basin properties accounted for approximately 441,673 MMcfe or 22% of our total estimated proved reserves at year end, of which 77% were proved developed and 78% were natural gas.

Permian Basin Properties

The Permian Basin is one of the largest and most prolific oil and natural gas producing basins in the United States extending over West Texas and southeast New Mexico. The Permian Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations. The majority of our producing wells in the Permian Basin are mature oil wells that also produce high-Btu casinghead gas with significant NGLs content. As of December 31, 2014, our Permian Basin properties consisted of 131,797 gross (93,389 net) leasehold acres. During 2014, our Permian Basin operations produced approximately 15,504 MMcfe, of which 59% was oil, condensate and NGLs. At December 31, 2014, these properties accounted for approximately 241,286 MMcfe or 12% of our total estimated proved reserves at year end, of which 77% were proved developed and 51% were oil, condensate and NGLs.

Gulf Coast Basin Properties

Our Gulf Coast Basin properties include properties in the onshore Gulf Coast area, North Louisiana, East Texas, South Texas and Mississippi.

Production from the North Louisiana properties comes from the East Haynesville and Cotton Valley fields. These properties include multiple productive zones including Cotton Valley, James Lime, Pettet, Haynesville, Smackover and Hosston. East Haynesville is located in Claiborne Parish, Louisiana and lies at a depth of about 10,000 to 13,000 feet. The Cotton Valley field is located in Webster Parish, Louisiana and is about 9,000 to 11,000 feet deep. Our production from East Texas properties comes from the Fairway (James Lime Unit) Field in Henderson and Anderson counties.

Most of our South Texas properties are operated by Lewis Petroleum and are located in two fields, Gold River North Field and Sun TSH Field, located in Webb and LaSalle Counties, Texas, respectively. Our working interest ranges from 25% to 100%. Most of the production is high Btu gas that is produced from the Olmos and Escondido sand formations from a depth averaging 7,500 feet.

We operate the majority of our Mississippi properties which are located in the Mississippi Salt Basin. Most of our production comes from the Parker Creek Field in Jones County, Mississippi, where our working interest is approximately 65%. We also have a license for 10 square miles of 3-D seismic data for the development of Parker Creek Field. Our production is mainly oil that produces from the Hosston Formation from a depth ranging from approximately 13,000 feet to 15,000 feet.

Production from our properties in the onshore Gulf Coast Basin comes from the Silsbee Field in Hardin County, Texas. The Silsbee Field is operated by Silver Oak Energy. Most of the Silsbee production is oil produced from the

Yegua formation.

As of December 31, 2014, our Gulf Coast Basin properties consisted of 93,432 gross (45,099 net) leasehold acres. During 2014, the Gulf Coast Basin properties produced approximately 5,654 MMcfe, of which 54% were oil, condensate and NGLs. At December 31, 2014, these properties accounted for approximately 181,509 MMcfe or 9% of our total estimated proved reserves at year end, of which 61% were proved developed and 63% were natural gas.

Big Horn Basin Properties

The Big Horn Basin is a prolific basin which is characterized by oil and natural gas fields with long production histories and multiple producing formations.

Our Elk Basin field is located in Park County, Wyoming and Carbon County, Montana. We operate all properties in the Elk Basin area which includes the Embar-Tensleep, Madison and Frontier formations as discussed below.

Embar-Tensleep Formation. Production in the Embar-Tensleep formation is being enhanced through a tertiary recovery technique involving effluent gas, or flue gas, from a natural gas processing facility located in the Elk Basin field. From 1949 to 1974, flue gas was injected into the Embar-Tensleep formation to increase pressure and improve production of resident hydrocarbons. Currently, we still use flue gas injection to maintain and improve production within this formation. Our wells in the Embar-Tensleep formation of the Elk Basin field are drilled to a depth of 5,100 to 6,600 feet.

Madison Formation. We plan to concentrate on implementing an injection program to enhance production in the Madison formation. The wells in the Madison formation of the Elk Basin field are drilled to a depth of 4,400 to 7,000 feet.

Frontier Formation. The Frontier formation is being produced through primary recovery techniques. The wells in the Frontier formation of the Elk Basin field are typically drilled to a depth of 1,400 to 2,700 feet.

We operate and own a 62% interest in the Elk Basin natural gas processing plant near Powell, Wyoming, which was first placed into operation in the 1940s. ExxonMobil Corporation (“Exxon”) owns a 34% interest in the Elk Basin natural gas processing plant, and other parties own the remaining 4% interest. This plant is a refrigeration natural gas processing plant that receives natural gas supplies through a natural gas gathering system from Elk Basin fields.

We also operate and own the Wildhorse pipeline system, which is an approximately 12-mile natural gas gathering system that transports approximately 1.0 MMcf/day of low-sulfur natural gas from the South Elk Basin fields to the Elk Basin natural gas processing plant.

Our Big Horn Basin properties are comprised of assets in Wyoming and the Elk Basin field in south central Montana. We own working interests ranging from 4% to 100% in our Big Horn Basin properties, which consisted of 24,512 gross (15,632 net) leasehold acres as of December 31, 2014. During 2014, our properties in the Big Horn Basin produced approximately 6,799 MMcfe, of which 88% was oil. At December 31, 2014, the Big Horn Basin properties accounted for approximately 104,437 MMcfe or 5% of our total estimated proved reserves at year end, of which 95% were proved developed and 95% were oil, condensate and NGLs.

Arkoma Basin Properties

Our Arkoma Basin properties include properties in the Woodford Shale, located in eastern Oklahoma, the Fayetteville Shale, located in Arkansas, and royalty interests and non-operated working interest in both states. As of December 31, 2014, our Arkoma Basin properties consisted of 148,467 gross (73,140 net) leasehold acres. During 2014, the Arkoma Basin properties produced approximately 20,113 MMcfe, of which 92% was natural gas. At December 31, 2014, the properties had total proved reserves of approximately 211,503 MMcfe or 10% of our total estimated proved reserves at year end, of which 80% were proved developed and 91% were natural gas.

Williston Basin Properties

Our Williston Basin properties are located in North Dakota and Montana, which include, among others, the Horse Creek Field, the Charlson Madison Unit and the Elk field. The Horse Creek field is located in Bowman County, North Dakota and has producing oil wells from multiple horizons in the Red River formation. The Charlson Madison Unit produces from the unitized Madison formation. The Elk field is operated and produces from wells in McKenzie County, North Dakota. As of December 31, 2014, our Williston Basin properties consisted of 550,996 gross (71,960 net) leasehold acres. During 2014, the properties produced approximately 2,843 MMcfe, of which 93% was oil. Our Williston Basin properties had estimated proved reserves at December 31, 2014 of 25,097 MMcfe or 1% of our total estimated proved reserves at year end, of which 96% were proved developed and 94% were oil.

Wind River Basin Properties

The Wind River Basin is located in central Wyoming. Our activities are concentrated primarily in the eastern Wind River Basin, along the greater Waltman Arch. Our natural gas production in this basin is gathered through our own gathering systems and delivered to markets through pipelines owned by Kinder Morgan Interstate and Colorado Interstate Gas ("CIG"). As of December 31, 2014, our Wind River Basin properties consisted of 231,685 gross (197,369 net) leasehold acres. During 2014, our Wind River Basin properties produced approximately 3,791 MMcfe, of which 87% was natural gas. At December 31, 2014, the properties had total proved reserves of approximately 36,842 MMcfe or 2% of our total estimated proved reserves, of which 95% were proved developed and 82% were natural gas.

Powder River Basin Properties

The Powder River Basin is primarily located in northeastern Wyoming. Our development operations are conducted in our coalbed methane ("CBM") fields. CBM wells are drilled to 1,500 feet on average, targeting the Big George Coals, typically producing water in a process called dewatering. This process lowers reservoir pressure, allowing the gas to desorb from the coal and flow to the well bore. As the reservoir pressure declines, the wells begin producing methane gas at an increasing rate. As the wells mature, the production peaks, stabilizes and then begins declining. The average life of a CBM well can range from five to eleven years depending on the coal seam. Our natural gas production in this basin is gathered through gathering and pipeline systems owned by Fort Union Gas Gathering, LLC and Thunder Creek Gas Services. As of December 31, 2014, our Powder River Basin properties consisted of 114,287 gross (66,866 net) leasehold acres. During 2014, the properties produced approximately 8,676 MMcfe, which was 100% natural gas. At December 31, 2014, the properties had total proved reserves of approximately 24,111 MMcfe or 1% of our total estimated proved reserves at year end, of which 77% were proved developed.

Oil, Natural Gas and NGLs Prices

We analyze the prices we realize from sales of our oil and natural gas production and the impact on those prices of differences in market-based index prices and the effects of our derivative activities. We market our oil and natural gas production to a variety of purchasers based on regional pricing. Our natural gas production is primarily sold under market sensitive contracts which are typically priced at a differential to the New York Mercantile Exchange ("NYMEX") price or the published natural gas index price for the producing area due to the natural gas quality and the proximity to major consuming markets. The West Texas Intermediate Cushing, or "WTI" price of crude oil is a widely used benchmark in the pricing of domestic and imported oil in the United States. The relative value of crude oil is mainly determined by its quality and location. In the case of WTI pricing, the crude oil is light and sweet, meaning that it has a higher specific gravity (lightness) measured in degrees of API ("American Petroleum Institute") gravity and low sulfur content, and is priced for delivery at Cushing, Oklahoma. In general, higher quality crude oils (lighter and sweeter) with fewer transportation requirements result in higher realized pricing for producers.

Certain of our natural gas marketing contracts determine the price that we are paid based on the value of the dry gas sold plus a portion of the value of NGLs extracted. Since title of the natural gas sold under these contracts passes at the outlet of the processing plant, we report residue volumes of natural gas in Mcf as production. As a result of the incremental NGLs value and the improved differential, the price we were paid per Mcf, before deductions for gathering, transportation and processing fees, for natural gas sold under certain contracts during 2014 increased to a level above NYMEX.

The average realized prices described below include deductions for gathering, transportation and processing fees, however, these prices do not include the impact of our hedges.

Production in the Green River Basin is predominantly natural gas and is processed for the recovery of NGLs. The processed natural gas is subject to a processing agreement with Western Gas Resources in their Granger Plant facility where we take our residue natural gas in-kind for sales and NGLs are sold pursuant to the terms of the processing agreement. We market our Green River Basin residue natural gas into the Rockies market through the use of multiple pipeline connections. During 2014, we received the average NYMEX price less $0.52 per Mcf in the Green River Basin. Due to the decrease in the ethane price during 2014, the Granger Plant made an economic decision to reject ethane effective January 2015.

Production in the Piceance Basin is predominantly natural gas and is processed for the recovery of NGLs. The processed gas is subject to a processing agreement with Enterprise Gas Processing LLC, in their Meeker Plant facility. We market our natural gas production into the Rockies market at the Northwest Rockies index pricing. During 2014, we received the average NYMEX price less $1.11 per Mcf in the Piceance Basin.

In the Permian Basin, most of our natural gas production is casinghead natural gas produced in conjunction with our oil production. Casinghead gas typically has a high Btu content and requires processing prior to sale to third parties. We have a number of processing agreements in place with gatherers/processors of our casinghead natural gas, and we share in the revenues associated with the sale of NGLs resulting from such processing, depending on the terms of the various agreements. For the year ended December 31, 2014, we received the average NYMEX price less $0.31 per Mcf in the Permian Basin. Our oil production is sold under month-to-month sales contracts with purchasers that take delivery of the oil volumes at the tank batteries adjacent to the producing wells. We sell oil production from our operated Permian Basin properties at the wellhead to third party gathering and marketing companies. During 2014, we received the average WTI price less $8.57 per barrel in the Permian Basin.

In the Gulf Coast Basin, our natural gas production has a high Btu content and requires processing prior to sale to third parties. Our proportionate share of the natural gas volumes are sold at the tailgate of the processing plant at the Houston Ship

Channel and Waha Gas Index pricing which typically results in a discount to NYMEX prices. For the year ended December 31, 2014, we received the average NYMEX price less $0.14 per Mcf.

The marketing of heavy sour crude oil production from our Big Horn Basin properties is done through our Clearfork pipeline, which transports the crude oil to local and other refiners through connections with other pipelines. Our Big Horn Basin sweet crude oil production is transported from the field by a third-party trucking company that delivers the crude oil to a centralized facility connected to a common carrier pipeline with delivery points accessible to local refiners in the Salt Lake City, Utah and Guernsey, Wyoming market centers. During 2014, we received the average NYMEX price less $12.54 per barrel in the Big Horn Basin. Effective March 2015, we entered into a sales contract under Western Canadian Select ("WCS") index pricing, which provides the opportunity for us to enter into hedges for our Elk Basin production and therefore reduce our exposure to price volatility.

Our Arkoma Basin production in the southeastern Oklahoma Woodford Shale consists predominately of natural gas with a mix of high Btu processed natural gas and unprocessed lean natural gas. The natural gas production is gathered by multiple third party entities with the processed natural gas ultimately delivered to the Atlas Resources natural gas processing complex. The processed natural gas is subject to a processing agreement with Atlas Resources, where we take our residue natural gas in-kind for sales, and NGLs are sold pursuant to the terms of the processing agreement. The lean natural gas is primarily delivered directly to market. The natural gas is marketed into the Enable Gas: East index and Transcontinental Gas Pipeline Corp: Zone 4 index via a firm transportation contract that was in place prior to our acquisition of these natural gas properties. For the year ended December 31, 2014, we received the average NYMEX price less $1.42 per Mcf.

Our Wind River Basin properties are predominantly natural gas plays with approximately two-thirds of the production being processed at natural gas plants for the extraction of NGLs. Our residue natural gas is sold into the Rockies market at the CIG price while the NGLs are sold to a third-party natural gas processor pursuant to a processing agreement. The Powder River natural gas production is classified as Coal Bed Methane ("CBM") gas and, as it is a very dry gas, is sold directly into the market upon being handled with conventional separation, treating, and transportation. The CBM gas is sold into the Rockies market at the CIG index price as well. During 2014, we received the average NYMEX price less $0.29 per Mcf in the Wind River Basin while we received the average NYMEX price less $2.16 per Mcf in the Powder River Basin.

In the Williston Basin, we produce a combination of sweet and legacy sour oil. This oil is both connected to oil pipelines as well as trucked out for sales and there is minimal natural gas associated with this production. During 2014, we received the average NYMEX price less $13.51 per barrel in the Williston Basin.

Oil, Natural Gas and NGLs Data

Estimated Proved Reserves

The following table presents our estimated net proved oil, natural gas and NGLs reserves and the present value of the estimated proved reserves at December 31, 2014, as estimated by our internal reserve engineers. The estimate of net proved reserves has not been filed with or included in reports to any federal authority or agency. The Standardized Measure value shown in the table is not intended to represent the current market value of our estimated oil, natural gas and NGLs reserves. Please see "Reserves Estimation Process" below and the "Supplemental Oil and Natural Gas Information" in the Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" of this Annual Report for additional information regarding our estimated proved reserves.

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Reserve Data:	
Estimated net proved reserves:	
Crude oil (MMBbls)	50.0
Natural gas (Bcf)	1,475.9
NGLs (MMBbls)	42.5
Total (Bcfe)	2,031.3
Proved developed (Bcfe)	1,377.6
Proved undeveloped (Bcfe)	653.7
Proved developed reserves as % of total proved reserves	68 %
Standardized Measure (in millions) [(1)(2)]	$2,975.7
Representative Oil and Natural Gas Prices [(3)]:	
Oil—WTI per Bbl	$94.87
Natural gas—Henry Hub per MMBtu	$4.36
NGLs—Volume-weighted average price per Bbl	$35.35

(1) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") (using the 12-month unweighted average of first-day-of-the-month price, the "12-month average price") without giving effect to non-property related expenses such as selling, general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion, amortization and accretion and discounted using an annual discount rate of 10%. Our Standardized Measure does not include future income tax expenses because we are not subject to income taxes and our reserves are owned by our subsidiaries which are also not subject to income taxes. Standardized Measure does not give effect to derivative transactions. For a description of our derivative transactions, please read "Item 1. Business—Operations—Price Risk and Interest Rate Management Activities" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

(2) For an explanation of Standardized Measure, please see "Supplemental Oil and Natural Gas Information" in the Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

(3) Oil and natural gas prices are based on spot prices per Bbl and MMBtu, respectively, calculated using the "12-month average price" for January through December 2014, with these representative prices adjusted by field for quality, transportation fees and regional price differentials to arrive at the appropriate net price. NGLs prices were calculated using the differentials to the WTI price per Bbl of $94.87.

The following tables set forth certain information with respect to our estimated proved reserves by operating basin as of December 31, 2014:

	Estimated Proved Developed Reserve Quantities				Estimated Proved Undeveloped Reserve Quantities				Estimated Proved Reserve Quantities
	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Total (Bcfe)
Operating Basin									
Green River Basin	335.2	3.1	6.8	394.5	310.1	2.9	7.2	370.4	764.9
Piceance Basin	268.1	2.0	10.0	339.9	78.7	0.8	3.1	101.8	441.7
Permian Basin	88.7	10.7	5.3	185.0	28.9	2.9	1.7	56.3	241.3
Gulf Coast Basin	65.3	5.5	2.1	111.3	48.3	3.2	0.4	70.2	181.5
Big Horn Basin	4.6	13.8	2.0	99.4	—	0.8	—	5.0	104.4
Arkoma Basin	159.1	—	1.8	169.8	33.2	—	1.4	41.7	211.5
Williston Basin	1.3	3.8	—	24.1	0.1	0.1	—	1.0	25.1
Wind River Basin	29.8	0.2	0.7	35.0	0.3	0.2	—	1.8	36.8
Powder River Basin	18.6	—	—	18.6	5.6	—	—	5.5	24.1
Total	970.7	39.1	28.7	1,377.6	505.2	10.9	13.8	653.7	2,031.3

	PV10 Value (1)		
Operating Basin	Developed (in millions)	Undeveloped	Total
Green River Basin	$580.5	$247.5	$828.0
Piceance Basin	460.3	54.9	515.2
Permian Basin	426.1	62.4	488.5
Gulf Coast Basin	284.5	135.1	419.6
Big Horn Basin	343.2	17.1	360.3
Arkoma Basin	191.4	12.5	203.9
Williston Basin	87.9	1.6	89.5
Wind River Basin	44.7	4.0	48.7
Powder River Basin	19.9	2.1	22.0
Total	$2,438.5	$537.2	$2,975.7

(1) PV10 is not a measure of financial or operating performance under generally accepted accounting principles, or "GAAP," nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. However, for Vanguard, PV10 is equal to the standardized measure of discounted future net cash flows under GAAP because the Company is not a tax paying entity. For our presentation of the standardized measure of discounted future net cash flows, please see "Supplemental Oil and Natural Gas Information" in the Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" of this Annual Report.

The data in the above tables represent estimates only. Oil, natural gas and NGLs reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGLs 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 oil, natural gas and NGLs that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future sales prices may differ from those assumed in these estimates. Please read “Item 1A. Risk Factors.”

In accordance with the guidelines of the SEC, our internal reserve engineers’ estimates of future net revenues from our properties, and the standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the unweighted arithmetic average first day of the month prices for the 12-month period ended December 31, 2014 for each product.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC"), is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to the timing of future production, which may prove to be inaccurate.

From time to time, we engage reserve engineers to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither the reserve engineers nor any of their respective employees have any interest in those properties and the compensation for these engagements is not contingent on their estimates of reserves and future net revenues for the subject properties. During 2014, we paid DeGolyer and MacNaughton ("D&M") approximately $0.1 million for all reserve and economic evaluations.

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2014, as estimated by our internal reserve engineers, were 653.7 Bcfe, consisting of 10.9 MMBbls of oil, 505.2 Bcf of natural gas and 13.8 MMBbls of NGLs. Our proved undeveloped reserves increased by 429.7 Bcfe during the year ended December 31, 2014, as compared to our proved undeveloped reserves as of December 31, 2013. The increase in proved undeveloped reserves during 2014 resulted from the addition of 517.4 Bcfe from the acquisitions of natural gas and oil properties completed during 2014 and a net increase of 34.6 Bcfe in revisions of previous quantities estimates and changes in prices. The increase is offset by a decrease of 101.2 Bcfe due to revisions in the timing of our drilling development plan primarily in the Arkoma Basin. Additionally, we developed approximately 21.1 Bcfe of our total proved undeveloped reserves booked as of December 31, 2013 through the drilling of 53 gross (6.08 net) wells.

We expect to spend approximately 57% of our planned five year future development costs within the next three years as reflected in our reserve report. During the year ended December 31, 2014, we spent $16.6 million or approximately 15% of our 2014 capital budget converting proved undeveloped reserves recorded at December 31, 2013 to proved developed reserves. Our development plan for drilling proved undeveloped wells includes the drilling of 371 net wells before the end of 2019 at an estimated cost of $806.3 million. This development plan calls for the drilling of 44 net wells during 2015, 80 net wells during 2016, 91 net wells during 2017, 83 net wells during 2018 and 73 net wells during 2019. Additionally, the expected plan of development of our natural gas proved undeveloped reserves, which represent 77% of our total proved undeveloped reserves at December 31, 2014, over the next five years is as follows:

	Percent of Natural Gas Proved Undeveloped Reserves Expected to be Converted
2015	16%
2016	19%
2017	22%
2018	22%
2019	21%
Total	100%

At December 31, 2014, none of our proved undeveloped properties are scheduled to be drilled on a date more than five years from the date the reserves were initially booked as proved undeveloped. Additionally, none of our proved undeveloped reserves at December 31, 2014 have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves.

Substantially all of our developed and undeveloped leasehold acreage is held by production, which means that as long as our wells on the acreage continue to produce, we will continue to hold the leases. The leases in which we hold an interest that are not held by production are not material to us.

Reserve Estimation Process

Estimates of proved reserves at December 31, 2014 were based on studies performed by our internal reservoir engineers in accordance with guidelines established by the SEC. Our reserve estimation process is a collaborative effort coordinated by our reservoir engineers in compliance with our internal controls for such process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including crude oil, natural gas and NGLs prices, production costs, future capital expenditures and our net ownership percentages are obtained from other departments within the Company. Our internal reservoir engineers perform review procedures with respect to such non-technical inputs. Reserve variances are discussed among the internal reservoir engineers and the Executive Vice President of Operations.

Our reserve engineering group is directly responsible for our reserve evaluation process and consists of four professionals, two of whom hold, at a minimum, bachelor's degrees in engineering. Within our Company, Michael Egerman, Reserves and Budget Manager, is the technical person primarily responsible for overseeing the preparation of the reserve estimates. Mr. Egerman has over 10 years of experience and graduated from the University of Texas at Austin with a Bachelor of Science degree in Petroleum Engineering in 2004. He is a member of the Society of Petroleum Engineers.

The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Independent Audit of Reserves

We engage independent petroleum engineers to audit a substantial portion of our reserve estimates. Our audit procedures require the independent engineers to prepare their own estimates of proved reserves for properties comprising at least 80% of our year-end proved reserves. Our Board of Directors requires that the independent petroleum engineers' estimate of reserve quantities for the properties audited by the independent petroleum engineers are within 10% of our internal estimate. Once completed, our year-end reserves are presented to senior management, including the President and Chief Executive Officer, the Executive Vice President and Chief Financial Officer, and the Executive Vice President of Operations, for approval.

For the year ended December 31, 2014, we engaged D&M, an independent petroleum engineering firm, to perform reserve audit services. The opinion by D&M for the year ended December 31, 2014 covered producing areas containing 80.7% of our proved reserves on a net-equivalent-barrel-of-oil basis. D&M's opinion indicates that the estimates of proved reserves prepared by our internal reserves engineers for the properties reviewed by D&M, when compared in total on a net-equivalent-barrel-of-oil basis, do not differ materially from the estimates prepared by D&M. Such estimates by D&M in the aggregate were within our 10% variation tolerance when compared to those prepared by our reserves engineering group. The report prepared by D&M was developed utilizing geological and engineering data we provided. The report of D&M dated February 19, 2015, which contains further discussion of the reserve estimates and evaluations prepared by D&M, as well as the qualifications of D&M's technical person primarily responsible for overseeing such estimates and evaluations, is attached as Exhibit 99.1 to this Annual Report on Form 10-K and incorporated herein by reference.

Within D&M, the lead technical person primarily responsible for overseeing the audit of our reserves is Mr. Gregory K. Graves. Mr. Graves is a Senior Vice President with D&M and has over 30 years of experience in oil and gas reservoir studies and reserves evaluations. He graduated from the University of Texas at Austin in 1984 with a Bachelor of Science Degree in Petroleum Engineering and is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists. Mr. Graves meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and NGLs and certain price and cost information for each of the periods indicated. Information for fields with greater than 15% of our total proved reserves have been listed separately in the table below for the year ended December 31, 2014. None of our fields had proved reserves that were greater than 15% of our total proved reserves during 2013 and 2012.

	Net Production(1)						Average Realized Sales Prices (2)			Production Cost (3)
	Crude Oil Bbls/day		Natural Gas Mcf/day		NGLs Bbls/day		Crude Oil Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl	Per Mcfe
Year Ended December 31, 2014										
Pinedale (Green River Basin)	659		72,090		3,028		$77.76	$3.96	$13.76	$ 0.43
Mamm Creek (Piceance Basin)	288		32,455		1,424		$72.85	$3.33	$25.71	$ 0.71
All other fields	8,096		122,953		3,107		$83.66	$3.27	$37.14	$ 1.54
Total	9,043		227,498		7,559		$82.88	$3.50	$25.62	$ 1.11
Year Ended December 31, 2013										
All fields	8,462		137,632		4,047		$82.26	$3.39	$33.76	$ 1.36
Year Ended December 31, 2012										
All other fields	7,536	53,695	53,695	84	1,813	45.11	$84.00	$4.47	$45.11	$ 1.85

(1) Average daily production for 2014 and 2013 calculated based on 365 days and for 2012 calculated based on 366 days including production for all of our acquisitions from the closing dates of these acquisitions.

(2) Average realized sales prices include the impact of hedges but exclude the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period. The average realized prices also reflect deductions for gathering, transportation and processing fees. For details on average sales prices without giving effect to the impact of hedges please see "Item 7. Management Discussion and Analysis of Financial Condition-Year Ended December 31, 2014 compared to Year Ended December 31, 2013" and "Item 7. Management Discussion and Analysis of Financial Condition -Year Ended December 31, 2013 compared to Year Ended December 31, 2012."

(3) Production costs include such items as lease operating expenses and exclude production taxes (severance and ad valorem taxes).

Productive Wells

The following table sets forth information at December 31, 2014 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas Wells		Oil Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Green River Basin	2,438	389	22	20	2,460	409

Piceance Basin	1,056	918	—	—	1,056	918
Permian Basin	554	264	2,536	691	3,090	955
Gulf Coast Basin	592	304	126	65	718	369
Big Horn Basin	5	3	299	215	304	218
Arkoma Basin	1,119	181	14	2	1,133	183
Williston Basin	30	9	137	76	167	85
Wind River Basin	135	128	9	8	144	136
Powder River Basin	687	391	—	—	687	391
Total	6,616	2,587	3,143	1,077	9,759	3,664

Developed and Undeveloped Leasehold Acreage

The following table sets forth information as of December 31, 2014 relating to our leasehold acreage.

	Developed Acreage (1)		Undeveloped Acreage (2)		Total Acreage	
	Gross (3)	Net (4)	Gross (3)	Net (4)	Gross (3)	Net (4)
Green River Basin	60,730	24,705	65,690	10,333	126,420	35,038
Piceance Basin	16,112	10,477	7,928	5,598	24,040	16,075
Permian Basin	115,254	83,536	16,543	9,853	131,797	93,389
Gulf Coast Basin	73,942	33,159	19,490	11,940	93,432	45,099
Big Horn Basin	23,392	14,559	1,120	1,073	24,512	15,632
Arkoma Basin	132,701	64,686	15,766	8,454	148,467	73,140
Williston Basin	65,270	35,280	485,726	36,680	550,996	71,960
Wind River Basin	22,989	21,026	208,696	176,343	231,685	197,369
Powder River Basin	65,106	37,868	49,181	28,998	114,287	66,866
Total	575,496	325,296	870,140	289,272	1,445,636	614,568

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such leasehold acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activity

The following is a description of the Company's drilling and completion activities during the year ended December 31, 2014.

In the Green River Basin, we participated in the drilling of 122 wells with an average working interest of 13%. We also participated in the completion of 136 wells with an average working interest of 12%. These wells are in Sublette County, in southwestern Wyoming and are directionally drilled from pads but are vertical through the 4,000 feet pay section. The average well depth is approximately 14,000 feet or a true vertical depth of 12,000 feet and are typically completed with an average of 16 frac stages.

We participated in the drilling of two coal bed methane wells in our Piceance Basin with a 21.5% working interest in each well. These wells were horizontal (dual lateral) wells drilled to the Fruitland Coal in La Plata County, Colorado. Total drilled depth is approximately 6,500 feet with true vertical depth of approximately 2,400 feet.

In the Permian Basin, we participated in drilling five vertical and three horizontal wells in the Midland, Dawson, Gaines and Ward Counties in Texas. Our working interests in these wells range between approximately 2% to 35%. We also completed a well in the Ector County where we have a 100% working interest. Most of these wells were drilled to a vertical depth of approximately 7,300 feet and were completed in the Clearfork, Tubb, Glorietta or

Wolfcamp formations. As a method to balance our capital investments, we promoted some of our working interest in a number of our Permian proved undeveloped locations including the horizontal Bone Springs wells in Ward County, Texas and are attempting to do the same with some vertical Wolfberry wells in Martin County, Texas.

In the Gulf Coast Basin, we participated in the drilling of three vertical wells in the Jones County in Mississippi with an average working interest of 22%. These wells were drilled to an average depth 19,000 feet. In addition, we participated in the completion of four wells with an average working interest of 22%.

In the Arkoma Basin, we participated in drilling 10 gross (0.2 net) horizontal wells in Hughes and Coal Counties in Woodford, Oklahoma and in completing 27 gross (3.5 net) horizontal wells in several counties also in Woodford, Oklahoma. We also participated in drilling 16 gross (0.5 net) and completing 33 gross (1.7 net) horizontal wells in Fayetteville, Oklahoma during the year in the White, Cleburne, Van Buren and Conway Counties.

In the Williston Basin, we participated in drilling three horizontal oil wells in the Williams and Billings counties in North Dakota with working interests ranging from 4% to 25% during 2014. These wells are in the Bakken shale and Three Forks formation and were drilled to an average total depth of about 22,500 feet or a true vertical depth of approximately 11,000 feet.

In the Powder River Basin, we drilled four vertical wells during 2014 in the Johnson field in Wyoming with an average working interest of 67%. These wells were drilled to a vertical depth of approximately 1,350 feet. We also participated in completing a well in the same field with a 16% working interest.

During 2015, we intend to concentrate our drilling on low risk, development opportunities with the majority of drilling capital focused on high Btu natural gas wells. We currently anticipate a capital budget for 2015 of approximately $113.5 million, excluding any potential future acquisitions. We expect to spend 50% of the 2015 capital budget in the Green River Basin where we will participate as a non-operated partner in the drilling and completion of vertical natural gas wells. Additionally, we expect to spend 25% of the 2015 capital budget in the Gulf Coast Basin on the newly acquired East Haynesville assets, drilling both vertical and horizontal wells and several recompletion projects. The balance of the 2015 budget is related to maintenance activities in our other operating areas.

The following table sets forth information with respect to wells completed during the years ended December 31, 2014, 2013 and 2012. Our drilling activity during these periods has consisted entirely of drilling development wells. We have not drilled any exploratory wells during these periods. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil, natural gas, and NGLs regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,		
	2014	2013	2012
Gross wells:			
Productive	215	78	27
Dry	—	—	—
Total	215	78	27
Net Development wells:			
Productive	27.2	6.9	6.6
Dry	—	—	—
Total	27.2	6.9	6.6

Operations

Principal Customers

For the year ended December 31, 2014, sales of oil, natural gas and NGLs to Anadarko Petroleum Corporation, Marathon Oil Company, Cardinal Midstream LLC, Plains Marketing, LP and Bill Barrett Corporation accounted for approximately 19%, 12%, 9%, 7% and 5%, respectively, of our oil, natural gas and NGLs revenues. Our top five purchasers during the year ended December 31, 2014 therefore accounted for 52% of our total revenues. To the extent these and other customers reduce the volumes of oil, natural gas and NGLs that they purchase from us and they are not replaced in a timely manner with a new customer, our revenues and cash available for distribution could decline. However, if we were to lose a customer, we believe a substitute purchaser could be identified in a timely manner and upon similar terms and conditions.

Delivery Commitments and Marketing Arrangements

Our oil and natural gas production is principally sold to marketers, processors, refiners, and other purchasers that have access to nearby pipeline, processing and gathering facilities. In areas where there is no practical access to pipelines, oil is trucked to central storage facilities where it is aggregated and sold to various markets and downstream purchasers. Our production sales agreements generally contain customary terms and conditions for the oil and natural gas industry, provide for sales based on prevailing market prices in the area, and generally are month-to-month or have terms of one year or less.

We generally sell our natural gas production from our operated properties on the spot market or under market-sensitive, short-term agreements with credit-worthy purchasers, including independent marketing companies, gas processing companies, and other purchasers who have the ability to pay the highest price for the natural gas production and move the natural gas under the most efficient and effective transportation agreements. Because all of our natural gas production from our operated properties is sold under market-priced agreements, we are positioned to take advantage of future increases in natural gas prices but we are also subject to any future price declines. We do market our own natural gas on some of our non-operated properties.

The marketing of heavy sour crude oil production from our Big Horn Basin properties is done through our Clearfork pipeline, which transports the crude oil to local and other refiners through connections to other export pipelines. Our Big Horn Basin sweet crude oil production is transported from the field by a third party trucking company that delivers the crude oil to a centralized facility connected to a common carrier pipeline with delivery points accessible to local refiners in the Salt Lake City, Utah and Guernsey, Wyoming market centers. We sell oil production from our operated Permian Basin properties at the wellhead to third-party gathering and marketing companies.

Our natural gas is transported through our own and third-party gathering systems and pipelines, and we incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third-party gatherer, processor or transporter. Capacity on these gathering systems and pipelines is occasionally limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas shippers. While our ability to market our natural gas has been only infrequently limited or delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected. In certain instances, we may enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes. Currently, a majority of our existing firm transportation agreements were assumed in connection with acquisitions of oil and natural gas properties. These agreements have term delivery commitments of fixed and determinable quantities of natural gas. Please see “Item 7. Management’s Discussion and Analysis and Results of Operations—Commitments and Contractual Obligations” for additional information regarding our long-term firm transportation contracts.

The following table sets forth information about material long-term firm transportation contracts for pipeline capacity, which typically require a demand charge. We source the gas to meet these commitments from our producing properties. We have certain commitments that we assumed as part of our acquisitions of oil and gas properties where the production from the acquired properties and the production of joint interest owners that we market were not adequate to meet the commitments resulting to us paying the set demand charge relating to the maximum daily quantity outlined in the contract.

Type of Arrangement	Pipeline System /Location	Deliverable Market	Gross Deliveries (MMBtu/d)	Term
Firm Transport	WIC Medicine Bow	Rocky Mountains	30,000	01/15 – 03/15

Firm Transport	WIC Medicine Bow	Rocky Mountains	25,000	01/15 – 06/20
Firm Transport	Questar Pipeline	Rocky Mountains	12,000	01/15 – 10/15
Firm Transport	Colorado Interstate Gas	Rocky Mountains	8,700	01/15 – 9/16
Firm Transport	Cheyenne Plains	Midcontinent	9,000	01/15 – 05/17
Firm Transport	Cheyenne Plains	Midcontinent	5,000	06/17 – 05/18
Firm Transport	Rockies Express	Northeast	25,000	01/15 – 11/19
Firm Transport	Gulf Crossing Pipeline	Mississippi-Alabama	10,000	01/15 – 07/15
Firm Transport	Gulf Crossing Pipeline	Mississippi-Alabama	10,000	01/15 – 07/16

Price Risk and Interest Rate Management Activities

We routinely enter into derivative transactions in the form of hedging arrangements to reduce the impact of oil, natural gas and NGLs price volatility on our cash flow from operations. Currently, we primarily use fixed-price swaps, basis swap contracts and other hedge option contracts to hedge oil and natural gas prices. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated for a period of time, but not eliminated, the potential effects of fluctuation in oil and natural gas prices on our cash flow from operations. For a description of our derivative positions, please read “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, leasing acreage, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staff substantially larger than ours or a different business model. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial, technical or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure unitholders that we will be able to compete satisfactorily when attempting to make further acquisitions.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, however, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We will not commence drilling operations on a property until we have cured any material title defects on such property. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we have obtained title opinions on a significant portion of our oil and natural gas properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, customary royalty interests, contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for taxes not yet payable and other burdens, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties, or will materially interfere with our use of these properties in the operation of our business.

Natural Gas Gathering

We own and operate a network of natural gas gathering systems in the Big Horn Basin, Piceance Basin and Gulf Coast Basin in East Texas. These systems gather and transport our natural gas and a small amount of third-party natural gas to larger gathering systems and intrastate, interstate and local distribution pipelines. Our network of natural gas gathering systems permits us to transport production from our wells with fewer interruptions and also minimizes any delays associated with a gathering company extending its lines to our wells. Our ownership and control of these lines enables us to:

- realize faster connection of newly drilled wells to the existing system;
- control pipeline operating pressures and capacity to maximize production;
- control compression costs and fuel use;
- maintain system integrity;
- control the monthly nominations on the receiving pipelines to prevent imbalances and penalties; and
- track sales volumes and receipts closely to assure all production values are realized.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in some of our operating areas, and as a result we generally perform the majority of our drilling in these areas during the summer and fall months. These seasonal anomalies can pose challenges for meeting our well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increased costs or delay our operations. Generally, but not always, oil is typically in higher demand in the summer for its use in road construction and natural gas is in higher demand in the winter for heating. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas consumers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Environmental and Occupational Health and Safety Matters

General. Our business involving the acquisition and development of oil and natural gas properties is subject to extensive and stringent federal, state and local laws and regulations governing the discharge of materials into the environment, environmental protection, and the health and safety of employees. These operations are subject to the same environmental, health and safety laws and regulations as other similarly situated companies in the oil and natural gas industry. These laws and regulations may:

- require the acquisition of permits before commencing drilling or other regulated activities;
- require the installation of expensive pollution control equipment and performance of costly remedial measures to mitigate or prevent pollution from historical and ongoing operations, such as pit closure and plugging of abandoned wells;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- impose specific health and safety criteria addressing worker protection;
- impose substantial liabilities for pollution resulting from operations; and
- require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement for operations affecting federal lands or leases.

Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, imposition of removal or remedial obligations, and the issuance of orders enjoining some or all of our operations deemed in non-compliance. Moreover, these laws and regulations may restrict our ability to produce oil, natural gas and NGLs by, among other things, limiting production from our wells, limiting the number of wells we are allowed to drill or limiting the locations at which we may conduct our drilling operations. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly well drilling, construction, completion and water management activities, or waste handling, disposal and clean-up requirements for the oil and natural gas industry could have a significant impact on our operating costs. We believe that operation of our wells is in substantial compliance with all current applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot provide any assurance on how future compliance with existing or newly adopted environmental laws and regulations may impact our properties or the operations. For the year ended December 31, 2014, we did not incur any material capital expenditures for performance of remediation or installation of pollution control equipment at any of our facilities;

however, we did incur capital expenditures in the ordinary course of business to comply with pollution control requirements. As of the date of this Annual Report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2015 or that will otherwise have a material adverse impact on our financial position or results of operations.

The following is a summary of the more significant existing environmental and occupational health and safety laws to which our business operations are subject and for which compliance may have a material adverse impact on our operations as well as the oil and natural gas exploration and production industry in general.

Waste Handling. The Resource Conservation and Recovery Act, as amended, or “RCRA,” and comparable state laws, regulate the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” as well as the disposal of non-hazardous wastes. Under the auspices of the U.S. Environmental Protection Agency, or “EPA,” individual states administer some or all of the federal provisions of RCRA, sometimes in conjunction with their own, more stringent state requirements. Drilling fluids, produced waters, and many other wastes associated with the exploitation, development, and production of crude oil, natural gas, or geothermal energy are currently regulated under RCRA’s less stringent non-hazardous waste provisions. However, by amendment of existing RCRA laws and regulations, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could increase our costs to manage and dispose of such generated wastes, which cost increase could be significant. In the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as RCRA hazardous wastes.

Hazardous Substance Releases. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as "CERCLA," or "Superfund," and analogous state laws, impose joint and several liability, without regard to fault or legality of conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that transported or disposed or arranged for the transportation or disposal of the hazardous substance found at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While materials are generated in the course of operation of our wells that may be regulated as hazardous substances, we have not received any pending notifications that we may be potentially responsible for cleanup costs under CERCLA.

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

Our Elk Basin assets include a natural gas processing plant. Previous environmental investigations of the Elk Basin natural gas processing plant indicate historical soil and groundwater contamination by hydrocarbons and the presence of asbestos-containing material at the site. Although the environmental investigations did not identify an immediate need for remediation of the suspected historical hydrocarbon contamination or abatement of the asbestos, the extent of the hydrocarbon contamination is not known and, therefore, the potential liability for remediating this contamination may be significant. In the event we cease operating the gas plant, the cost of decommissioning it and addressing the previously identified environmental conditions and other conditions, such as waste disposal, could be significant. We do not anticipate ceasing operations at the Elk Basin natural gas processing plant in the near future nor a need to commence remedial activities at this time. However, a regulatory agency could require us to investigate and remediate any hydrocarbon contamination even while the gas plant remains in operation. In addition, we also own and operate the Fairway natural gas processing plant in the Gulf Coast Basin. As of December 31, 2014, we have recorded $9.0 million as future abandonment liability for the estimated cost for decommissioning the Elk Basin and Fairway natural gas processing plants. Due to the significant uncertainty associated with the known and unknown environmental liabilities at the gas plants, our estimate of the future abandonment liability includes a large reserve. Our estimates of the future abandonment liability and compliance costs are subject to change and the actual cost of these items could vary significantly from those estimates.

Water Discharges. The Federal Water Pollution Control Act, as amended, or “Clean Water Act,” and analogous state laws impose restrictions and strict controls on the discharge of pollutants, including produced waters and other oil and natural gas wastes, into state waters as well as waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the relevant state with delegated authority. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure, or “SPCC,” requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by an oil spill or release. If an oil spill or release were to occur as a result of our operations, we expect that it would be contained and remediated in accordance with our SPCC plan together with the assistance of trained first responders and any oil spill response contractor that we may have engaged to address such spills and releases. The Clean Water Act and analogous state laws can impose substantial administrative, civil and criminal penalties for non-compliance including spills and other non-authorized discharges.

Fluids associated with oil and natural gas production, consisting primarily of salt water, are disposed by injection in below ground disposal wells. These disposal wells are regulated pursuant to the Underground Injection Control, or UIC, program established under the federal Safe Drinking Water Act, or SDWA, and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. While we believe that our disposal well operations substantially comply with requirements under the UIC program, a change in disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of salt water and ultimately increase the cost of our operations. For example, there exists a growing concern that the injection of saltwater and other fluids into below ground disposal wells triggers seismic activity in certain areas, including Texas, where we operate. In response to these concerns, in October 2014, the Texas Railroad Commission, or TRC, published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of salt water and other fluids, which could delay production schedules and also result in increased costs.

The Oil Pollution Act of 1990, as amended, or "OPA," amends the Clean Water Act and sets minimum standards for prevention, containment and cleanup of oil spills. OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that are the site of a release of oil into waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. We believe we are in substantial compliance with the Clean Water Act, OPA and analogous state laws.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions and other similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.

From time to time Congress has considered adopting legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states in which the Company operates, including Montana, North Dakota, Texas and Wyoming, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, as the State of New York announced in December 2014 with regard to fracturing activities in New York. Also, local government may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing activities.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability and control of well insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Air Emissions. The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from sources through air emissions permitting programs and also impose various monitoring and reporting requirements. These laws and their implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to result in the emission of new or increased existing air pollutants, obtain and strictly comply with air permit requirements containing various emissions and operational limitations, or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. To date, we believe that no significant difficulties have been encountered in obtaining air permits. Oil and natural gas exploration and production facilities may be required to incur certain capital expenditures in the future for air control equipment in connection with obtaining and maintaining operating permits and approvals for emissions of pollutants. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which rulemaking proposed to revise the National Ambient Air Quality Standard, or "NAAQS," for ozone between 65 to 70 parts per billion, or "ppb," for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. The EPA also requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. If the EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could apply to our operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Activities on Federal Lands. Oil and natural gas exploitation and production activities on federal lands are subject to the National Environmental Policy Act, as amended, or "NEPA." NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will typically prepare an Environmental Assessment to assess the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Our current production activities, as well as proposed development plans, on federal lands require governmental permits or similar authorizations that are subject to the requirements of NEPA. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

Climate Changes. In response to findings made by the EPA that emissions of carbon dioxide, methane, and other greenhouse gases, or "GHGs," present an endangerment to public health and the environment because emissions of such gasses are contributing to the warming of the earth's atmosphere and other climatic changes, the EPA has adopted regulations under existing provisions of the Clean Air Act that establish Title V operation and Prevention of Significant Deterioration, or "PSD," construction permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which typically will be established by the states. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from certain sources including, among others, onshore and offshore oil and natural gas production facilities in the United States on an annual basis, which include certain of our operations. We are conducting monitoring of GHG emissions from certain of our operations in accordance with the GHG emissions reporting rule and we believe that our monitoring and reporting activities are in substantial compliance with applicable reporting obligations.

While from time to time Congress has considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. For example, pursuant to President Obama’s Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025.

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. Still other scientists have concluded the earth is entering a new "Maunder Minimum," characterized by reduced solar activity which will materially cool the earth for some decades to come, producing related significant physical effect such as increased frequency of cold snaps, shortened growing seasons, and extensive periods of heavy freezing and other climatic events. If such effects were to occur, they could have an adverse effect on the provision of our production.

Endangered Species Act Considerations. The federal Endangered Species Act, as amended, or “ESA,” restricts activities that may affect endangered or threatened species or their habitats. While some of our facilities or leased acreage may be located in areas that are designated as habitat for endangered or threatened species, we believe our operations are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service, or “FWS,” is required to make a determination on listing of numerous species as endangered or threatened under the ESA through the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. For example, on March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, New Mexico, Colorado and Oklahoma, where we conduct operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, or WAFWA, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken’s habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken’s habitat. The listing of the lesser prairie chicken as a threatened species or, alternatively, entry into certain range-wide conservation planning agreements such as WAFWA, could result in increased costs to us from species protection measures, time delays or limitations on the drilling program’s activities, which costs, delays or limitations may be significant to our business.

Occupational Safety and Health. We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or “OSHA,” and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we maintain and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules, orders and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. For example, on July 1, 2014, the North Dakota Industrial Commission adopted Order No. 24665, or the "July 2014 Order," pursuant to which the agency adopted legally enforceable "gas capture percentage goals" targeting the capture of 74% of natural gas produced in the State by October 1, 2014, 77% percent of such gas by January 1, 2015, 85% of such gas by January 1, 2016 and 90% of such gas by October 1, 2020. The July 2014 Order establishes an enforcement mechanism for policy recommendations that were previously adopted by the North Dakota Industrial Commission in March 2014. Those recommendations required all exploration and production operators applying for new drilling permits in the state after June 1, 2014 to develop Gas Capture Plans that provide measures for reducing the amount of natural gas flared by those operators so as to be consistent with the agency's now-implemented gas capture percentage goals. In particular, the July 2014 Order provides that after an initial 90-day period, wells must meet or exceed the North Dakota Industrial Commission's gas capture percentage goals on a per-well, per-field, county, or statewide basis. Failure to comply with the gas capture percentage goals will result in an operator having to restrict its production to 200 barrels of oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or 100 barrels of oil per day if less than 60% of such monthly volume of natural gas is captured. While we believe that we were in compliance with these requirements as of December 31, 2014 and expect to remain in compliance in the future, there is no assurance that we will be able to remain in compliance in the future or that such future compliance will not have a material adverse effect on our business and operation results. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil, natural gas and NGLs we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Regulation of Transportation and Sales. The availability, terms and cost of transportation significantly affect sales of oil, natural gas and NGLs. The interstate transportation of natural gas is subject to federal regulation primarily by the Federal Energy Regulatory Commission, or “FERC,” under the Natural Gas Act of 1938, or “NGA.” FERC regulates interstate natural gas pipeline transportation rates and service conditions, which may affect the marketing and sales of natural gas. FERC requires interstate pipelines to offer available firm transportation capacity on an open-access, non-discriminatory basis to all natural gas shippers. FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. State laws and regulations generally govern the gathering and intrastate transportation of natural gas. Natural gas gathering systems in the states in which we operate are generally required to offer services on a non-discriminatory basis and are subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without discrimination in favor of one producer over another producer or one source of supply over another source of supply.

The ability to transport oil and NGLs is generally dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act, or subject to regulation by the particular state in which such transportation takes place. Laws and regulation applicable to pipeline transportation of oil largely require pipelines to charge just and reasonable rates published in agency-approved tariffs and require pipelines to provide non-discriminatory access and terms and conditions of service. The justness and reasonableness of interstate oil and natural gas liquid pipeline rates can be challenged at FERC through a protest or a complaint and, if such a protest or complaint results in a lower rate than that on file, pipeline shippers may be eligible to receive refunds or, in the case of a complaining shipper, reparations for the two-year period prior to the filing of the complaint. Certain regulations imposed by FERC, by the United States Department of Transportation and by other regulatory authorities on pipeline transporters in recent years could result in an increase in the cost of pipeline transportation service. We do not believe, however, that these regulations affect us any differently than other producers.

Under the Energy Policy Act of 2005, or “EPAct 2005,” Congress made it unlawful for any entity, as defined in the EPAct 2005, including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services regulated by the FERC that violates the FERC’s rules. FERC’s rules implementing EPAct 2005 make it unlawful for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA and the Natural Gas Policy Act up to $1,000,000 per day per violation. Pursuant to authority granted to FERC by EPAct 2005, FERC has also put in place additional regulations intended to prevent market manipulation and to promote price transparency. For example, FERC has imposed new rules discussed below requiring wholesale purchasers and sellers of natural gas to report to FERC certain aggregated volume and other purchase and sales data for the previous calendar year. While EPAct 2005 reflects a significant expansion of the FERC's enforcement authority, we do not anticipate that we will be affected by EPAct 2005 any differently than energy industry participants.

In 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report on Form No. 552, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Pursuant to Order 704, we may be required to annually report to FERC, starting May 1 of each year, information regarding natural gas purchase and sale transactions depending on the volume of natural gas transacted during the prior calendar year.

On August 6, 2009, the Federal Trade Commission, or "FTC," issued a Final Rule prohibiting manipulative and deceptive conduct in the wholesale petroleum markets. The Final Rule applies to transactions in crude oil, gasoline, and petroleum distillates. The FTC promulgated the Final Rule pursuant to Section 811 of the Energy Independence and Security Act of 2007, or "EISA," which makes it unlawful for anyone, in connection with the wholesale purchase or sale of crude oil, gasoline or petroleum distillates, to use any "manipulative or deceptive device or contrivance, in contravention of such rules and regulations as the Federal Trade Commission may prescribe." The Final Rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale, from: (a) knowingly engaging in any act, practice, or course of business – including making any untrue statement of material fact that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas companies with whom we compete.

The price at which we buy and sell natural gas is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. Sales of condensate and NGLs are not currently regulated and are made at market prices. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or "CFTC." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties.

State Regulation. The various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and NGLs, including imposing severance and other production-related taxes and requirements for obtaining drilling permits. Reduced rates or credits may apply to certain types of wells and production methods.

States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not currently regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil, natural gas and NGLs that may be produced from our wells, to increase our cost of production, to limit the number of wells or locations we can drill and to limit the availability of pipeline capacity to bring our products to market.

In addition to production taxes, Texas, Oklahoma and Montana each impose ad valorem taxes on oil and natural gas properties and production equipment. Wyoming and New Mexico impose an ad valorem tax on the gross value of oil and natural gas production in lieu of an ad valorem tax on the underlying oil and natural gas properties. Wyoming also imposes an ad valorem tax on production equipment. North Dakota imposes an ad valorem tax on gross oil and natural gas production in lieu of an ad valorem tax on the underlying oil and gas leases or on production equipment used on oil and gas leases.

The petroleum industry participants are also subject to compliance with various other federal, state and local regulations and laws. Some of these regulations and those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these regulations and laws will have a material adverse effect upon the unitholders.

Federal, State or Native American Leases. Our operations on federal, state, or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the BLM and other agencies. For example, in May 2013, the BLM published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. The BLM is expected to promulgate a final rule in the first half of 2015.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards and other potential events that can adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance except for our Elk Basin and Fairway gas plants as well as for our Piceance compressor assets. We may not obtain insurance for certain risks if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs that is not fully covered by insurance, it could adversely affect us.

Employees

As of February 25, 2015, we had 260 full-time employees. We also contract for the services of independent consultants involved in land, regulatory, tax, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Offices

Our principal executive office is located at 5847 San Felipe, Suite 3000, Houston, Texas 77057. Our main telephone number is (832) 327-2255.

Available Information

Our website address is www.vnrllc.com. We make our website content available for information purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Annual Report. We make available on our website under "Investor Center-SEC Filings," free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. The SEC also maintains a website at www.sec.gov that contains reports, proxy statements and other information regarding SEC registrants, including us.

You may also find information related to our corporate governance, board committees and company code of business conduct and ethics on our website. Among the information you can find there is the following:

- Audit Committee Charter;
- Nominating and Corporate Governance Committee Charter;
- Compensation Committee Charter;
- Conflicts Committee Charter;
- Code of Business Conduct and Ethics; and
- Corporate Governance Guidelines.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

We may not have sufficient cash from operations to pay monthly distributions on our common units following establishment of cash reserves and payment of operating costs.

We may not have sufficient cash flow from operations each month to pay distributions. Under the terms of our limited liability company agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserve amounts that our board of directors establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from month to month based on, among other things:

- the amount of oil, natural gas and NGLs we produce;
- the price at which we are able to sell our oil, natural gas and NGLs production;
- the level of our operating costs;
- the level and success of our price risk management activities;
- the level of our interest expense which depends on the amount of our indebtedness and the interest payable thereon;
- the level of our capital expenditures; and
- voluntary or required payments on our debt agreements.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of our capital expenditures;
- our ability to make working capital borrowings under our financing arrangements to pay distributions;

- the cost of acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital needs;
- timing and collectibility of receivables;
- prevailing economic conditions; and
- the amount of cash reserves established by our board of directors for the proper conduct of our business.

As a result of these factors, the amount of cash we distribute in any month to our unitholders may fluctuate significantly from month to month. If we do not achieve our expected operational results or cannot borrow the amounts needed, we may not be able to pay the full, or any, amount of the monthly distributions, in which event the market price of our common units may decline substantially.

Growing the Company will require significant amounts of debt and equity financing, which may not be available to us on acceptable terms, or at all.

We plan to fund our growth through acquisitions with proceeds from sales of our debt and equity securities and borrowings under our Reserve-Based Credit Facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms or in the proportions that we expect, or at all, and we may be unable to refinance our Reserve-Based Credit Facility upon maturity.

A significant increase in our indebtedness, or an increase in our indebtedness that is proportionately greater than our issuances of equity, as well as the credit market and debt and equity capital market conditions discussed above could negatively impact our ability to remain in compliance with the financial covenants under our Reserve-Based Credit Facility which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or not pursue growth opportunities.

Our financing arrangements have substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations.

As of February 27, 2015, we had an aggregate amount of approximately $1.9 billion outstanding under our Reserve-Based Credit Facility, the Senior Notes and Lease Financing Obligations with additional borrowing capacity of approximately $634.5 million under our Reserve-Based Credit Facility. As a result of our indebtedness, we will use a portion of our cash flow to pay interest and principal when due, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate.

Our Reserve-Based Credit Facility and the Senior Notes contain certain covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates, as well as containing covenants requiring us to maintain certain financial ratios and tests.

Our borrowing base is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will re-determine the borrowing base based on an engineering report with respect to our oil, natural gas and NGLs reserves, which will take into account the prevailing oil, natural gas and NGLs prices at such time. In the future, we may not be able to access adequate funding under our Reserve-Based Credit Facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations.

Continued declines in commodity prices could result in a redetermination lowering our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Reserve-Based Credit Facility. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid within 30 days, or in six monthly installments beginning within 30 days, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our Reserve-Based Credit Facility.

Continued low oil, natural gas and NGLs prices and other factors have resulted, and in the future may result, in ceiling test or goodwill write-downs and other impairments of our asset carrying values.

We use the full cost method of accounting to report our oil and natural gas properties. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural gas properties may not exceed a “ceiling limit,” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a “ceiling test write-down.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write-down would not impact cash flow from operating activities, but it could have a material adverse effect on our results of operations in the period incurred and would reduce our members’ equity.

In accordance with the guidance contained within ASC Topic 805, “Business Combinations,” (“ASC Topic 805”), upon the acquisition of oil and natural gas properties, the Company records an asset based on the measurement of the fair value of the properties acquired determined using forward oil and natural gas price curves at the acquisitions dates, which can have several price increases over the entire reserve life. As discussed above, capitalized oil and natural gas property costs are limited to a ceiling based on the present value of future net revenues, computed using a flat price for the entire reserve life equal to the historical 12-month average price, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is less than the total capitalized costs, we are required to write down capitalized costs to the ceiling. As a result, there is a risk that we will be required to record an impairment of our oil and natural gas properties if certain attributes exist, such as declining oil and natural gas prices.

We recorded a non-cash ceiling test impairment of oil and natural gas properties for the year ended December 31, 2014 of $234.4 million as a result of a decline in realized oil and natural gas prices at the measurement date, December 31, 2014. Such impairment was recognized during the fourth quarter of 2014. The most significant factor affecting the 2014 impairment related to the properties that we acquired in the Piceance Acquisition. The fair value of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) was higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. The fourth quarter 2014 impairment was calculated based on prices of $4.36 per MMBtu for natural gas and $94.87 per barrel of crude oil.

We expect to record an additional impairment of our oil and natural gas properties during 2015 as a result of declining oil and natural gas prices. Based on the 11-month average oil, natural gas and NGLs prices through February 1, 2015 and if such prices do not change during March 2015, we estimate that, on a pro forma basis, we will record a ceiling test write down on our existing assets of approximately $530.9 million at March 31, 2015 and an additional write down of $562.4 million for the remainder of the year ending December 31, 2015. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, natural gas and NGLs for the remainder of 2015, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and natural gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

Additionally, we have recorded goodwill which represents the excess of the purchase price over the estimated fair value of the net assets acquired in the ENP Purchase. Significant price declines could cause us to record an impairment of goodwill, which would be reflected as non-cash charge against current earnings.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

A principal component of our business strategy is to grow our asset base and production through the acquisition of oil and natural gas properties characterized by long-lived, stable production. The character of newly acquired properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. The changes in the characteristics and risk profiles of such new properties will in turn affect our risk profile, which may negatively affect our ability to issue equity or debt securities in order to fund future acquisitions and may inhibit our ability to renegotiate our existing credit facilities on favorable terms.

Our future distributions and proved reserves will be dependent upon the success of our efforts to prudently acquire, manage and develop oil and natural gas properties that conform to the acquisition profile described in this Annual Report.

In addition to ownership of the properties currently owned by us, unless we acquire properties in the future containing additional proved reserves or successfully develop proved reserves on our existing properties, our proved reserves will decline as the reserves attributable to the underlying properties are produced. In addition, if the costs to develop or operate our properties increase, the estimated proved reserves associated with properties will be reduced below the level that would otherwise be estimated. We will manage and develop our properties, and the ultimate value to us of such properties which we acquire will be dependent upon the price we pay and our ability to prudently acquire, manage and develop such properties. As a result, our future cash distributions will be dependent to a substantial extent upon our ability to prudently acquire, manage and develop such properties.

Suitable acquisition candidates may not be available on terms and conditions that we find acceptable, we may not be able to obtain financing for certain acquisitions, and acquisitions pose substantial risks to our businesses, financial conditions and results of operations. Even if future acquisitions are completed, the following are some of the risks associated with acquisitions, which could reduce the amount of cash available from the affected properties:

- some of the acquired properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
- we may assume liabilities, including environmental liabilities that were not disclosed or that exceed their estimates;
- we may be unable to integrate acquired properties successfully and may not realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may incur additional debt related to future acquisitions.

Oil, natural gas and NGLs prices are volatile and have decreased dramatically over the last quarter of 2014 and the beginning of 2015. Sustained lower prices of oil and natural gas could have a material adverse impact on us.

Our financial condition, profitability and future growth and the carrying value of our oil and natural gas properties depend substantially on prevailing oil, natural gas and NGLs prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Prices for oil and natural gas have decreased dramatically over the latter half of 2014.

The amount we are able to borrow under our senior revolving credit facility is subject to periodic redetermination based in part on current oil and natural gas prices and on changing expectations of future prices. Continued declines in oil and natural gas prices may result in a reduction in our borrowing base at the next redetermination. A reduction in our borrowing base could require us to repay any indebtedness in excess of the borrowing base. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness unless we meet one of two alternative tests. The first test applies to all indebtedness and requires that, after giving effect to the incurrence of additional debt, our fixed charge coverage ratio (which is the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters) will be at least 2.0 to 1.0. The second test applies to borrowings under credit agreements and limits these borrowings to the greater of a fixed sum of $750 million and 30% of our adjusted consolidated net tangible assets, which is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves. Lower oil and natural gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties, which may cause us to incur impairment charges under full cost accounting rules.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries ("OPEC") and other producing countries to agree upon and maintain oil prices and production levels;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;
- the price and availability of alternative fuels;
- the price of foreign imports;
- worldwide economic conditions; and
- the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

Continued low prices or further declines in prices for oil, natural gas and NGLs prices would not only reduce our revenue, but could reduce the amount of oil, natural gas and NGLs that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. If the oil and gas industry continues to experience low prices or experiences significant further price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms or make distributions to our unitholders, all of which can affect the value of our units.

A widening of commodity differentials and our inability to enter into hedge contracts for a sufficient amount of our production at favorable pricing could materially adversely impact our financial condition, results of operations and cash flows from operations.

Our crude oil, natural gas and NGLs are priced in the local markets where the production occurs based on local or regional supply and demand factors. The prices that we receive for our crude oil, natural gas and NGLs production are generally lower than the relevant benchmark prices, such as NYMEX, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential. We may not be able to accurately predict crude oil, natural gas and NGLs differentials.

Price differentials may widen in the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are based on WTI or natural gas index prices and the NGLs hedges are based on the Oil Price Information Service postings as well as market-negotiated ethane spot prices, so we may be subject to basis risk if the differential on the products we sell widens from

those benchmarks and we do not have a contract tied to those benchmarks. We have entered into fixed-price swaps derivative contracts to cover a portion of our NGLs production to reduce exposure to fluctuations in NGLs prices. Currently, we are unable to hedge widening oil differentials in certain operating areas. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive and our inability to enter into hedge contracts at favorable pricing and for a sufficient amount of our production could adversely affect our financial condition, results of operations and cash flows from operations in the future.

Our limited ability to hedge our NGLs production could adversely impact our net cash provided by operating activities and results of operations.

A liquid, readily available and commercially viable market for hedging NGLs has not developed in the same way that exists for crude oil and natural gas. The current direct NGLs hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits our ability to hedge our NGLs production effectively or at all. As a result, our net cash provided by operating activities and results of operations could be adversely impacted by fluctuations in the market prices for NGLs products.

Unless we replace our reserves, our existing reserves and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

Producing oil and natural gas wells extract hydrocarbons from underground structures referred to as reservoirs. Reservoirs contain a finite volume of hydrocarbon reserves referred to as reserves in place. Based on prevailing prices and production technologies, only a fraction of reserves in place can be recovered from a given reservoir. The volume of the reserves in place that is recoverable from a particular reservoir is reduced as production from that well continues. The reduction is referred to as depletion. Ultimately, the economically recoverable reserves from a particular well will deplete entirely, and the producing well will cease to produce and will be plugged and abandoned. In that event, we must replace our reserves. Unless we are able over the long-term to replace the reserves that are produced, investors in our units should consider the cash distributions that are paid on the units not merely as a "distribution yield" on the units, but as a combination of both a return of capital and a return on investment. Investors in our units will have to obtain the return of capital invested out of cash flow derived from their investments in units during the period when reserves can be economically recovered. Accordingly, we give no assurances that the distributions our unitholders receive over the life of their investment will meet or exceed their initial capital investment.

Adverse developments in our operating areas would reduce our ability to make distributions to our unitholders.

Our properties are located in Wyoming, Colorado, Texas, New Mexico, Louisiana, Mississippi, Montana, Arkansas, Oklahoma and North Dakota. An adverse development in the oil and natural gas business of any of these geographic areas, such as in our ability to attract and retain field personnel or in our ability to comply with local regulations, could have an impact on our results of operations and cash available for distribution to our unitholders.

Our acquisition activities will subject us to certain risks.

We have expanded our operations through acquisitions. Any acquisition involves potential risks, including, among other things: the validity of our assumptions about reserves, future production, revenues and costs, including synergies; an inability to integrate successfully the businesses we acquire; a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions; a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions; the assumption of unknown liabilities including, for example, historical spills or releases, losses or costs for which we are not indemnified or for which our indemnity is inadequate; the diversion of management's attention to other business concerns; an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; the incurrence of other significant charges, such as impairment of recorded goodwill or other intangible assets, asset devaluation or restructuring charges; unforeseen difficulties encountered in operating in new geographic areas; an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes; and customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

If our acquisitions do not generate increases in available cash per unit, our ability to make cash distributions to our unitholders could materially decrease.

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

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties, including timing of drilling and other scheduled operations activities, compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. In the past, we have changed our development plans for certain proved undeveloped reserves and expect future development plans may also change as the operators of our outside operated properties adjust their capital plans based on prevailing market conditions. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

The amount of cash that we have available for distribution to our unitholders depends primarily upon our cash flow and not our profitability.

The amount of cash that we have available for distribution depends primarily on our cash flow, including cash from reserves and working capital or other borrowings, and not solely on our GAAP net income, which is affected by non-cash items. As a result, we may be unable to pay distributions even when we record net income, and we may be able to pay distributions during periods when we incur net losses.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. We prepare our own estimates of proved reserves and engage DeGolyer and MacNaughton ("D&M"), an independent petroleum engineering firm, to audit a substantial portion of our reserves. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, the calculation of estimated reserves requires certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs, any of which assumptions may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. For example, if natural gas prices decline by $1.00 per MMBtu and oil prices declined by $6.00 per barrel, the standardized measure of our proved reserves as of December 31, 2014 would decrease from $3.0 billion to $2.3 billion, based on price sensitivity generated from an internal evaluation. Our standardized measure is calculated using unhedged oil and natural gas prices and is determined in accordance with the rules and regulations of the SEC. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGLs we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves that we disclose in our annual financial statements is not necessarily the same as the current market value of our estimated proved reserves.

We base the estimated discounted future net cash flows from our proved reserves using a 12-month average price and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- the volume, pricing and duration of our oil and natural gas hedging contracts;

- supply of and demand for oil, natural gas and NGLs;

- actual prices we receive for oil, natural gas and NGLs;
- our actual operating costs in producing oil, natural gas and NGLs;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to unitholders.

Our operations require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves and adversely affect our ability to make distributions to our unitholders.

The oil and natural gas industry is capital intensive. We have made and ultimately expect to continue to make substantial capital expenditures in our business for the development, production and acquisition of oil, natural gas and NGLs reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and our financing arrangements. Our cash flow from operations and our access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil, natural gas and NGLs we are able to produce from existing wells;
- the prices at which our oil, natural gas and NGLs are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our Reserve-Based Credit Facility decrease as a result of lower oil, natural gas and NGLs prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels or to replace or add to our reserves. Our Reserve-Based Credit Facility restricts our ability to obtain new debt financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our Reserve-Based Credit Facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a possible decline in our reserves and production and a reduction in our cash available for distribution.

Our business depends on gathering and compression facilities owned by third parties and transportation facilities owned by third-party transporters and we rely on third parties to gather and deliver our oil, natural gas and NGLs to certain designated interconnects with third-party transporters. Any limitation in the availability of those facilities or delay in providing interconnections to newly drilled wells would interfere with our ability to market the oil, natural gas and NGLs we produce and could reduce our revenues and cash available for distribution.

The marketability of our oil, natural gas and NGLs production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties in the respective operating areas. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, compression or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport the additional production. As a result, we may not be able to sell the oil and natural gas production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering, compression and transportation facilities, could reduce our revenues and cash available for distribution.

Our sales of oil, natural gas and NGLs and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The FTC, FERC and CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas and NGLs or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We are subject to FERC requirements related to our use of capacity on natural gas pipelines that are subject to FERC regulation. Any failure on our part to comply with the FERC's regulations and policies, or with an interstate pipeline's tariff, could result in the imposition of civil and criminal penalties.

Climate change legislation and regulatory initiatives restricting emissions of GHGs may adversely affect our operations, our cost structure, or the demand for oil and natural gas.

In response to findings made by the EPA that emissions of GHGs present an endangerment to public health and the environment because emissions of such gasses are contributing to the warming of the earth's atmosphere and other climatic changes, the EPA, has adopted regulations under existing provisions of the Clean Air Act establishing Title V operating and PSD construction permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which typically will be established by the states. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities, should those facilities exceed threshold permitting levels of GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from certain sources including, among others, onshore and offshore oil and natural gas production facilities in the United States on an annual basis, which include certain of our operations. While from time to time Congress has considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. 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 provision of services. Still other scientists have concluded the earth is entering a new "Maunder Minimum," characterized by reduced solar activity which will materially cool the earth for some decades to come, producing related significant physical effect such as increased frequency of cold snaps, shortened growing seasons, and extensive periods of heavy freezing and other climatic events. If such effects were to occur, they could have an adverse effect on the provision of our production.

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

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Columbia in September of 2012 although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap," "security-based swap," "swap dealer" and "major swap participant". The Act and CFTC Rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Act and CFTC rules on us and the timing of such effects. The Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Act and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures or to make distributions. Finally, the Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act and regulations is to lower commodity prices. Any of these consequences could have material, adverse effect on us, our financial condition, and our results of operations.

We depend on certain key customers for sales of our oil, natural gas and NGLs. To the extent these and other customers reduce the volumes of oil, natural gas and NGLs they purchase from us, or to the extent these customers cease to be creditworthy, our revenues and cash available for distribution could decline.

For the year ended December 31, 2014, sales of oil, natural gas and NGLs to Anadarko Petroleum Corporation, Marathon Oil Company, Cardinal Midstream LLC, Plains Marketing, LP and Bill Barrett Corporation accounted for approximately 19%, 12%, 9%, 7%, and 5%, respectively, of our oil, natural gas and NGLs revenues. Our top five purchasers during the year ended December 31, 2014 therefore accounted for 52% of our total revenues. To the extent these and other customers reduce the volumes of oil, natural gas and NGLs that they purchase from us and they are not replaced in a timely manner with a new customer, our revenues and cash available for distribution could decline.

We are subject to compliance with environmental and occupational safety and health laws and regulations that may expose us to significant costs and liabilities.

The operations of our wells are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, environmental protection, and the health and safety of employees. These laws and regulations may impose numerous obligations on our operations including the acquisition of permits, including drilling permits, to conduct regulated activities; the incurrence of capital expenditures to mitigate or prevent releases of materials from our facilities; restriction of types, quantities and concentration of materials that can be released into the environment; limitation or prohibition of construction and operating activities in environmental sensitive areas such as wetlands, wilderness regions and other protected areas; the imposition of substantial liabilities for pollution resulting from our operations; and the application of specific health and safety criteria addressing worker protection. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of investigatory, corrective action or remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose joint and several strict liability for costs required to clean up and restore sites where hazardous substances or wastes have been disposed of or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property or natural resource damage allegedly caused by the release of hazardous substances or other waste products into the environment.

We may incur significant environmental costs and liabilities in the performance of our operations as a result of our handling petroleum hydrocarbons, hazardous substances and wastes, because of air emissions and wastewater discharges relating to our operations, and due to historical industry operations and waste disposal practices by us or prior operators or other third parties over whom we had no control. For example, an accidental release of petroleum hydrocarbons from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, property and natural resource damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which rulemaking proposed to revise NAAQS for ozone between 65 to 70 ppb for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. The EPA also requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. If the EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could apply to our operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business. We may not be able to recover some or any of these costs from insurance. Please read “Item 1. Business—Operations—Environmental and Occupational Health Safety Matters.”

Laws and regulations pertaining to threatened and endangered species could delay or restrict the Company's operations and cause it to incur substantial costs.

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include the ESA, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The FWS may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or 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 or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS is required to make a determination on the listing of numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or could result in limitations on its exploration and production activities that could have an adverse effect on the Company's ability to develop and produce reserves. For example, on March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, New Mexico, Colorado and Oklahoma, where we conduct operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, or WAFWA, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken’s habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken’s habitat. The listing of the lesser prairie chicken as a threatened species or, alternatively, entry into certain range-wide conservation planning agreements such as WAFWA, could result in increased costs to us from species protection measures, time delays or limitations on the drilling program’s activities, which costs, delays or limitations may be significant to our business.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs, operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, and other similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.

From time to time Congress has considered adopting legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states in which we operate, including Montana, North Dakota, Texas and Wyoming, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting public disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, as the State of New York announced in December 2014 with regard to fracturing activities in New York. Also, local government may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing activities.

Locations that we or the operators of our properties decide to drill may not yield oil or natural gas in commercially viable quantities.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we or the operators of our properties drill dry holes or wells that are productive but do not produce enough to be commercially viable after drilling, operating and other costs. If we or the operators of our properties drill future wells that we identify as dry holes, our drilling success rate would decline and may adversely affect our results of operations and our ability to pay future cash distributions at expected levels.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of oil or natural gas in these areas.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our ability to pay distributions.

Our prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional geological and engineering analysis. Based on a variety of factors, including future oil, natural gas and NGLs prices, the generation of additional seismic or geological information, the availability of drilling rigs and other factors, we may decide not to drill one or more of these prospects.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing leasehold acreage. As of December 31, 2014, we have identified 1,254 proved undeveloped drilling locations and over 3,931 additional drilling locations. These identified drilling locations represent a significant part of our strategy. The SEC's reserve reporting rules include a general requirement 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. To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of such reserves could also have a negative effect on the borrowing base under our Reserve-Based Credit Facility.

Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, drilling and operating costs and drilling results. In addition, we have not assigned any proved reserves to the over 3,931 unproved drilling locations we have identified and scheduled for drilling and therefore there may exist greater uncertainty with respect to the success of drilling wells at these drilling locations. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial position, results of operations and our ability to pay distributions.

Drilling for and producing oil, natural gas and NGLs are high-risk activities with many uncertainties that could adversely affect our financial condition or results of operations and, as a result, our ability to pay distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil or natural gas can be uneconomical, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- shortages of or delays in obtaining water for hydraulic fracturing operations;
- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- fires;
- blowouts, craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids; and

- pipeline capacity curtailments.

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

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

We may incur substantial additional debt in the future to enable us to pursue our business plan and to pay distributions to our unitholders.

Our business requires a significant amount of capital expenditures to maintain and grow production levels. Commodity prices have historically been volatile, and we cannot predict the prices we will be able to realize for our production in the future. As a result, we may borrow, to the extent available, significant amounts under our Reserve-Based Credit Facility in the future to enable us to pay monthly distributions. Significant declines in our production or significant declines in realized oil, natural gas and NGLs prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

If we borrow to pay distributions, we are distributing more cash than we are generating from our operations on a current basis. This means that we are using a portion of our borrowing capacity under our Reserve-Based Credit Facility to pay distributions rather than to maintain or expand our operations. If we use borrowings under our Reserve-Based Credit Facility to pay distributions for an extended period of time rather than toward funding capital expenditures and other matters relating to our operations, we may be unable to support or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on our future indebtedness to pay these distributions, will reduce our cash available for distribution on our common units. If we borrow to pay distributions during periods of low commodity prices and commodity prices remain low, we may have to reduce or suspend our distribution in order to avoid excessive leverage and debt covenant violations.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in some of our operating areas and as a result, we generally perform the majority of our drilling in these areas during the summer and fall months. These seasonal anomalies can pose challenges for meeting our well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increased costs or delay our operations. Additionally, many municipalities impose weight restrictions on the paved roads that lead to our jobsites due to the muddy conditions caused by spring thaws. This limits our access to these jobsites and our ability to service wells in these areas. Generally, but not always, oil is in higher demand in the summer for its use in road construction and natural gas is in higher demand in the winter for heating. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas consumers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Our price risk management activities could result in financial losses or could reduce our cash flow, which may adversely affect our ability to pay distributions to our unitholders.

We enter into derivative contracts to reduce the impact of oil, natural gas and NGLs price volatility on our cash flow from operations. Currently, we primarily use fixed-price swaps, basis swap contracts and other hedge option contracts to hedge oil and natural gas prices. Please read “Item 1. Business—Operations—Price Risk and Interest Rate Management Activities” and “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our price risk management activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors, customers and by counterparties to our price risk management arrangements. Some of our vendors, customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors, customers and counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. 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 vendors', customers' and counterparties' liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors, customers and/or counterparties could reduce our ability to make distributions to our unitholders.

We depend on senior management personnel, each of whom would be difficult to replace.

We depend on the performance of Scott W. Smith, our President and Chief Executive Officer, Richard A. Robert, our Executive Vice President and Chief Financial Officer and Britt Pence, our Senior Vice President of Operations. We maintain no key person insurance for either Mr. Smith, Mr. Robert or Mr. Pence. The loss of any or all of Messrs. Smith, Robert and Pence could negatively impact our ability to execute our strategy and our results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil, natural gas and NGLs, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low oil, natural gas and NGLs prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

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

Our operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, we could also be liable for personal injuries, property and natural resource damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas we may produce and sell. A major regulatory requirement inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff. Please read “Item1. Business—Operations—Environmental and Occupational Health and Safety Matters” and “Item 1. Business—Operations—Other Regulation of the Oil and Natural Gas Industry” for a description of the laws and regulations that affect us.

Shortages of drilling rigs, supplies, oilfield services, equipment and crews could delay our operations and reduce our cash available for distribution.

Higher oil, natural gas and NGLs prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. In the past, we and other oil, natural gas and NGLs companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Sustained periods of lower oil, natural gas and NGLs prices could bring about the closure or downsizing of entities providing drilling services, supplies, oil field services, equipment and crews. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available for distribution.

Risks Related to Our Structure

We may issue additional units without unitholder approval, which would dilute their existing ownership interests.

We may issue an unlimited number of limited liability company interests of any type, including units, without the approval of our unitholders.

The issuance of additional units or other equity securities may have the following effects:

- the proportionate ownership interest of unitholders in us may decrease;

- the amount of cash distributed on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the units may decline.

Our limited liability company agreement restricts the voting rights of unitholders owning 20% or more of our units.

Our limited liability company agreement restricts the voting rights of unitholders by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than persons who acquire such units with the prior approval of the board of directors, cannot vote on any matter. Our limited liability agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting unitholders' ability to influence the manner or direction of management.

Our limited liability company agreement provides for a limited call right that may require unitholders to sell their units at an undesirable time or price.

If, at any time, any person owns more than 90% of the units then outstanding, such person has the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining units then outstanding at a price not less than the then-current market price of the units. As a result, unitholders may be required to sell their units at an undesirable time or price and therefore may receive a lower or no return on their investment. Unitholders may also incur a tax liability upon a sale of their units.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our limited liability company agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The Company pays distributions on monthly basis. The value of our units may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may have difficulty issuing more equity to recapitalize.

Our management may have conflicts of interest with the unitholders. Our limited liability company agreement limits the remedies available to our unitholders in the event unitholders have a claim relating to conflicts of interest.

Conflicts of interest may arise between our management on the one hand, and the Company and our unitholders on the other hand, related to the divergent interests of our management. Situations in which the interests of our management may differ from interests of our non-affiliated unitholders include, among others, the following situations:

- our limited liability company agreement gives our Board of Directors broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distribution. For example, our management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;

- our management team, subject to oversight from our Board of Directors, determines the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of additional units and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders; and

- affiliates of our directors are not prohibited under our limited liability company agreement from investing or engaging in other businesses or activities that compete with the Company.

The price of our common and cumulative preferred units could be subject to wide fluctuations and unitholders could lose a significant part of their investment.

During 2014, the quoted market prices of our common and cumulative preferred units fluctuated as follows:

	Closing Low	Closing High
Common unit (VNR)	$13.59	$32.95
Series A Preferred unit (VNRAP)	$17.72	$27.10
Series B Preferred unit (VNRBP)	$15.91	$25.01
Series C Preferred unit (VNRCP)	$16.30	$24.94

The market prices of our common and cumulative preferred units are subject to fluctuations in response to a number of factors, most of which we cannot control, including:

- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded limited partnerships and limited liability companies;

- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry, including fluctuations in commodity prices;

- changes in securities analysts' recommendations and their estimates of our financial performance;

- the public's reaction to our press releases, announcements and our filings with the SEC;

- changes in market valuations of similar companies;

- departures of key personnel;

- commencement of or involvement in litigation;

- variations in our quarterly results of operations or those of other oil and natural gas companies;

- variations in the amount of our monthly cash distributions; and

- future issuances and sales of our units.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 18-607 of the Delaware Revised Limited Liability Company Act, or the "Delaware Act," we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, members or unitholders who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited liability company for the distribution amount. A purchaser of common units who becomes a member or unitholder is liable for the obligations of the transferring member to make contributions to the limited liability company that are known to such purchaser of units at the time it became a member and for unknown obligations if the liabilities could be determined from our limited liability company agreement.

An increase in interest rates may cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited liability company interests. Reduced demand for our units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to material amounts of entity-level taxation for state tax purposes, then our cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on us being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited liability company ("LLC") under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we may pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%, and may likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gain, loss, deduction or credit recognized by us would flow through to unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of VNR as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our LLC Agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state, or local income tax purposes, the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are required to pay Texas franchise tax which is assessed on Texas sourced taxable margin defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. If any other state were to impose a tax upon us as an entity, the cash available for distribution to our unitholders would be reduced.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration’s budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration’s proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. However, it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

If the IRS contests the federal income tax positions we take, the market for our units may be adversely impacted and the costs of any IRS contest will reduce our cash available for distribution.

We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from their share of our taxable income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income result in a decrease in the tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation deductions. In addition, because the amount realized includes a unitholder's share of our liabilities, if a unitholders sells their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Treatment of distributions on our Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our Preferred Units than the holders of our common units.
The Company will treat distributions on the Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Preferred Units as ordinary income. Although a holder of Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, the company anticipates accruing and making the guaranteed payment distributions monthly. Otherwise, the holders of Preferred Units are generally not anticipated to share in the Company's items of income, gain, loss or deduction. Nor will the Company allocate any share of its nonrecourse liabilities to the holders of Preferred Units.

A holder of Preferred Units will be required to recognize gain or loss on a sale of units equal to the difference between the unitholder's amount realized and tax basis in the units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the unitholder to acquire such Preferred Unit. Gain or loss recognized by a unitholder on the sale or exchange of a Preferred Unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of Preferred Units will not be allocated a share of the Company’s items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in the Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. Distributions to non-U.S. holders of the Preferred Units will be treated as “effectively connected income” (which will subject holders to U.S. net income taxation and possibly the branch profits tax) and will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of federal income tax actually due, non-U.S. holders may be required to file

United States federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax exempt investors is not certain. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor with respect to the consequences of owning our Preferred Units.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning units that may result in adverse tax consequences to them.

Investments in units by tax-exempt entities, including employee benefit plans, IRAs and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations and accordingly, our counsel is unable to opine as to the validity of this method. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (e.g. a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for U.S. federal income tax purposes.

We will be considered to have constructively terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders receiving two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes but instead, we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax election and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax year in which the termination occurs.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The Fiscal Year 2016 Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress which would implement many of these proposals. 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 domestic 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 any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in Wyoming, Colorado, Texas, New Mexico, Louisiana, Mississippi, Montana, Arkansas, Oklahoma and North Dakota. Each of these states, other than Texas and Wyoming, imposes an income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in “Item 1. Business,” and is incorporated herein by reference.

We have office leases in Houston, Ft. Worth and Odessa, Texas; and Gillette, Wyoming. As of December 31, 2014, the lease for the Houston office covers approximately 37,156 square feet of office space with a term ending on February 29, 2020. Our leases for the Ft. Worth and Odessa offices cover approximately 7,315 square feet and 6,500 square feet of office space, respectively, and run through December 31, 2015 and June 30, 2019, respectively. In Wyoming, the lease for our Gillette office covers approximately 5,000 square feet with a lease term expiring on April 30, 2018. The total annual costs of our office leases for 2014 was approximately $1.6 million.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

We are defendants in certain legal proceedings arising in the normal course of our business. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flow. In addition, we are not aware of any 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 STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are traded on the NASDAQ under the symbol "VNR." On February 25, 2015, there were 83,709,271 common units outstanding and approximately 436 unitholders, which does not include beneficial owners whose units are held by a clearing agency, such as a broker or a bank. On February 25, 2015, the market price for our common units was $17.67 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $1.4 billion. The following table presents the high and low sales price for our common units during the periods indicated.

	Common Units	
	High	Low
2014		
Fourth Quarter	$27.72	$12.57
Third Quarter	$33.04	$26.11
Second Quarter	$32.21	$29.26
First Quarter	$31.50	$29.11
2013		
Fourth Quarter	$29.75	$27.13
Third Quarter	$28.45	$24.23
Second Quarter	$29.93	$27.08
First Quarter	$29.64	$26.21

Stock Performance Graph. The performance graph below compares total unitholder return on our common units, with the total return of the Standard & Poor's 500 Index, or "S&P 500 Index," and our Peer Group Index, a weighted composite of eight oil and natural gas production publicly traded partnerships. The partnerships included in our peer group are Linn Energy, LLC, BreitBurn Energy Partners, L.P., Legacy Reserves LP, EV Energy Partners, LP, Mid-Con Energy Partners, Memorial Production Partners LP and LRR Energy, L.P. We have selected the members in our peer group based on annual revenue, market capitalization, total assets, and areas of operation. Total return includes the change in the market price, adjusted for reinvested dividends or distributions, for the period shown on the performance graph and assumes that $100 was invested in VNR at the last reported sale price of units as reported by New York Stock Exchange ($5.90) on December 31, 2008, and in the S&P 500 Index and our peer group index on the same date. The results shown in the graph below are not necessarily indicative of future performance. The following performance graph and related information shall not be deemed "soliciting material" or "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or the Exchange Act, each as amended, except to the extent that we specifically incorporate it by reference into such filing.

	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12	12/31/13	12/31/14
Vanguard Natural Resources, LLC	$100.00	$437.94	$641.68	$645.04	$671.10	$831.58	$465.67
Peer Group Index	$100.00	$214.44	$342.52	$284.44	$275.84	$285.35	$131.38
S&P 500 Index	$100.00	$126.45	$145.49	$148.55	$172.31	$228.10	$259.30

Distributions Declared. The following table shows the amount per unit, record date and payment date of the cash distributions we paid on each of our common units attributable to each period presented. Future distributions are at the discretion of our board of directors and will depend on business conditions, earnings, our cash requirements and other relevant factors. On February 17, 2015, our board of directors declared a cash distribution for our common and Class B unitholders attributable to the month of January 2015 of $0.1175 per common and Class B unit, or $1.41 on an annualized basis, which will be paid on March 17, 2015 to Vanguard unitholders of record on March 2, 2015. This represents a reduction from the distribution attributable to the month of December 2014 of $0.21 per common and Class B unit, or $2.52 on an annualized basis.

	Cash Distributions Per Unit	Record Date	Payment Date
2014			
Fourth Quarter			
December	$0.2100	February 2, 2015	February 13, 2015
November	$0.2100	January 2, 2015	January 14, 2015
October	$0.2100	December 1, 2014	December 15, 2014
Third Quarter			
September	$0.2100	November 3, 2014	November 14, 2014
August	$0.2100	October 1, 2014	October 15, 2014
July	$0.2100	September 2, 2014	September 12, 2014
Second Quarter			
June	$0.2100	August 1, 2014	August 14, 2014
May	$0.2100	July 1, 2014	July 15, 2014
April	$0.2100	June 2, 2014	June 13, 2014
First Quarter			
March	$0.2100	May 1, 2014	May 15, 2014
February	$0.2100	April 1, 2014	April 14, 2014
January	$0.2075	March 3, 2014	March 17, 2014
2013			
Fourth Quarter			
December	$0.2075	February 3, 2014	February 14, 2014
November	$0.2075	January 2, 2014	January 15, 2014
October	$0.2075	December 2, 2013	December 13, 2013
Third Quarter			
September	$0.2075	November 1, 2013	November 14, 2013
August	$0.2075	October 1, 2013	October 15, 2013
July	$0.2075	September 3, 2013	September 13, 2013
Second Quarter			
June	$0.2050	August 1, 2013	August 14, 2013
May	$0.2050	July 1, 2013	July 15, 2013
April	$0.2050	June 3, 2013	June 14, 2013
First Quarter			
March	$0.2025	May 1, 2013	May 15, 2013
February	$0.2025	April 1, 2013	April 12, 2013
January	$0.2025	March 1, 2013	March 15, 2013

Our limited liability company agreement requires that, within 90 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any month ending prior to liquidation:

(a) the sum of:

(i) all our and our subsidiaries' cash and cash equivalents (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) on hand at the end of that quarter; and

(ii)

all our and our subsidiaries' additional cash and cash equivalents (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made subsequent to the end of such quarter,

(b) less the amount of any cash reserves established by the board of directors (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) to:

(i) provide for the proper conduct of our or our subsidiaries' business (including reserves for future capital expenditures, including drilling and acquisitions, and for our and our subsidiaries' anticipated future credit needs);

(ii) comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which we or any of our subsidiaries is a party or by which we are bound or our assets are subject; or

(iii) provide funds for distributions to our unitholders with respect to any one or more of the next four quarters;

provided that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of a quarter but on or before the date of determination of available cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if the board of directors so determines.

Distributions on the Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, unless the 15th day falls on a weekend or holiday, in which case it will be paid on the next business day, when, as and if declared by our board of directors. We will pay cumulative distributions in cash on the Preferred Units on a monthly basis at a monthly rate of 7.875% per annum of the liquidation preference of $25.00 per Series A Cumulative Preferred Unit, a monthly rate of 7.625% per annum of the liquidation preference of $25.00 per Series B Cumulative Preferred Unit and a monthly rate of 7.75% per annum of the liquidation preference of $25.00 per Series C Cumulative Preferred Unit.

Equity Compensation Plans. See "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" for information regarding our equity compensation plans as of December 31, 2014.

Unregistered Sale of Equity Securities and Use of Proceeds. During the three months ended December 31, 2014, one of our wholly-owned subsidiaries purchased 134,770 of our common units on the open market at the then prevailing market price. The average price paid per common unit was $18.54.

ITEM 6. SELECTED FINANCIAL DATA

Set forth below is our summary of our consolidated financial and operating data for the periods indicated for Vanguard Natural Resources, LLC.

The selected financial data should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" included in this Annual Report.

The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in our business. This measure is not calculated or presented in accordance with GAAP. We explain this measure below and reconcile it to the most directly comparable financial measure calculated and presented in accordance with GAAP in "—Non-GAAP Financial Measure."

	Year Ended December 31, [5] 2014	2013	2012[6]	2011[7]	2010
	(in thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$268,685	$268,922	$233,153	$236,003	$50,022
Natural gas sales	285,439	124,513	47,270	47,977	25,778
NGLs sales	70,489	49,813	29,933	28,862	9,557
Net gains on commodity derivative contracts [1]	163,452	11,256	36,846	6,735	7,797
Total revenues	788,065	454,504	347,202	319,577	93,154
Costs and Expenses:					
Production:					
Lease operating expenses	132,515	105,502	74,366	63,944	18,471
Production and other taxes	61,874	40,430	29,369	28,621	6,840
Depreciation, depletion, amortization and accretion	226,937	167,535	104,542	84,857	22,231
Impairment of oil and natural gas properties	234,434	—	247,722	—	—
Selling, general and administrative expenses [2]	30,839	25,942	22,466	19,779	10,134
Total costs and expenses	686,599	339,409	478,465	197,201	57,676
Income (Loss) from Operations:	101,466	115,095	(131,263)	122,376	35,478
Other Income (Expense):					
Interest expense	(69,765)	(61,148)	(41,891)	(28,994)	(5,766)
Net losses on interest rate derivative contracts	(1,933)	(96)	(6,992)	(4,962)	(2,148)
Net gain (loss) on acquisitions of oil and natural gas properties	34,523	5,591	11,111	(367)	(5,680)
Other income (expense)	54	69	220	77	1
Total other expense	(37,121)	(55,584)	(37,552)	(34,246)	(13,593)
Net Income (Loss)	64,345	59,511	(168,815)	88,130	21,885
Less: Net income attributable to non-controlling interest	—	—	—	(26,067)	—
Net Income (Loss) Attributable to Vanguard Unitholders	$64,345	$59,511	$(168,815)	$62,063	$21,885
Less: Distributions to Preferred unitholders	(18,197)	(2,634)	—	—	—
Net Income (Loss) Attributable to Common and Class B unitholders	$46,148	$56,877	$(168,815)	$62,063	$21,885
Net Income (Loss) Per Common and Class B Unit:					
Basic	$0.56	$0.78	$(3.11)	$1.95	$1.00
Diluted	$0.55	$0.77	$(3.11)	$1.95	$1.00
Distributions Declared Per Common and Class B Unit [3]	$2.52	$2.46	$2.79	$2.28	$2.15
Weighted Average Common Units Outstanding:					
Basic	81,611	72,644	53,777	31,370	21,500
Diluted	82,039	72,992	53,777	31,370	21,500
Weighted Average Class B Units Outstanding	420	420	420	420	420
Cash Flow Data:					
Net cash provided by operating activities	$339,752	$260,965	$204,490	$176,332	$71,577
Net cash used in investing activities	$(1,446,202)	$(397,977)	$(839,244)	$(236,350)	$(429,994)

Net cash provided by financing activities	$1,094,632	$137,267	$643,466	$61,041	$359,758
Other Financial Information:					
Adjusted EBITDA attributable to Vanguard unitholders interest (4)	$421,445	$309,745	$230,512	$164,603	$80,396

(1) Oil and natural gas derivative contracts were used to reduce our exposure to changes in oil and natural gas prices. In 2008, all commodity derivative contracts were either de-designated as cash flow hedges or they failed to meet the hedge documentation requirements for cash flow hedges. As a result, (a) for the cash flow hedges that were settled in 2008

through 2011, the change in fair value through December 31, 2007 was reclassified to earnings from accumulated other comprehensive loss and is classified as gain (loss) on commodity cash flow hedges and (b) the changes in the fair value of commodity derivative contracts are recorded in earnings and classified as gain (loss) on commodity derivative contracts.

(2) Includes \$11.7 million, \$5.9 million, \$5.4 million, \$3.0 million and \$1.0 million of non-cash unit-based compensation expense in 2014, 2013, 2012, 2011 and 2010, respectively.

(3) Includes distributions declared during the respective periods. Due to the change in the payment of our distributions from quarterly to monthly starting with our July 2012 distribution, the distributions declared during 2012 include 14 months of distributions compared to 12 months of distributions for each of the other years presented. See Item 8. Financial Statements and Supplementary Data—Note 9 for further detail on distributions declared.

(4) See "—Non-GAAP Financial Measure" below.

(5) From 2010 through 2014, we acquired certain oil and natural gas properties and related assets, as well as additional interests in these assets. The operating results of these properties were included with ours from the closing date of the acquisitions forward.

(6) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

(7) On December 31, 2010, we acquired all of the member interests in Encore Energy Partners GP, LLC, the general partner of Encore Energy Partners LP ("ENP") and certain limited partnership interests in ENP (the "ENP Purchase") together representing a 46.7% aggregate equity interest in ENP at the date of the ENP Purchase. On December 1, 2011, we acquired the remaining 53.4% of the limited partnership interests in ENP not held by us through a merger (the "ENP Merger") with one of our wholly-owned subsidiaries. We refer to the ENP Purchase and ENP Merger collectively as the "ENP Acquisition." The operating results of the subsidiaries we acquired in the ENP Purchase through the date of the completion of the ENP Merger on December 1, 2011 were subject to a 53.4% non-controlling interest.

	As of December 31,				
	2014	2013	2012	2011	2010 [1]
	(in thousands)				
Balance Sheet Data:					
Cash and cash equivalents	\$—	\$11,818	\$11,563	\$2,851	\$1,828
Short-term derivative assets	142,114	21,314	46,690	2,333	16,523
Other current assets	144,119	73,025	55,738	51,508	34,435
Oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment	2,975,806	1,810,517	1,576,236	1,217,985	1,063,403
Long-term derivative assets	83,583	60,474	53,240	1,105	1,479
Goodwill [2]	420,955	420,955	420,955	420,955	420,955
Other assets	27,015	91,538	35,712	19,626	16,569
Total Assets	\$3,793,592	\$2,489,641	\$2,200,134	\$1,716,363	\$1,555,192
Short-term derivative liabilities	\$3,583	\$10,992	\$5,366	\$12,774	\$6,209
Other current liabilities	175,021	114,411	74,136	33,064	34,261

Term loan-current	—	—	—	—	175,000
Long-term debt	1,932,816	1,007,879	1,247,631	771,000	410,500
Long-term derivative liabilities	1,380	4,085	11,996	20,553	30,384
Other long-term liabilities	146,676	83,939	63,541	35,051	29,445
Members’ equity	1,534,116	1,268,335	797,464	843,921	320,731
Non-controlling interest in subsidiary	—	—	—	—	548,662
Total Liabilities and Members’ Equity	$3,793,592	$2,489,641	$2,200,134	$1,716,363	$1,555,192

(1) Includes the fair value of the ENP assets and liabilities we acquired on December 31, 2010.

(2) Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the ENP Purchase completed on December 31, 2010.

Summary Reserve and Operating Data

The following tables show estimated net proved reserves based on a reserve report prepared by us and audited by independent petroleum engineers, D&M, and certain summary unaudited information with respect to our production and sales of oil, natural gas and NGLs. You should refer to “Item 1A. Risk Factors,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Item 1. Business—Oil, Natural Gas and NGLs Data—Estimated Proved Reserves” and “Item 1. Business—Oil, Natural Gas and NGLs Data—Production and Price History” included in this Annual Report in evaluating the material presented below.

	As of December 31, 2014	
Reserve Data:		
Estimated net proved reserves:		
Crude oil (MMBbls)	50.0	
Natural gas (Bcf)	1,475.9	
NGLs (MMBbls)	42.5	
Total (Bcfe)	2,031.3	
Proved developed (Bcfe)	1,377.6	
Proved undeveloped (Bcfe)	653.7	
Proved developed reserves as % of total proved reserves	68	%
Standardized Measure (in millions) (1)(2)	$2,975.7	
Representative Oil and Natural Gas Prices (3):		
Oil—WTI per Bbl	$94.87	
Natural gas—Henry Hub per MMBtu	$4.36	
NGLs—Volume-weighted average price per Bbl	$35.35	

(1) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using the 12-month average price as defined below) without giving effect to non-property related expenses such as selling, general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion, amortization and accretion and discounted using an annual discount rate of 10%. Our Standardized Measure does not include future income tax expenses because we are not subject to income taxes and our reserves are owned by our subsidiaries which are also not subject to income taxes. Standardized Measure does not give effect to derivative transactions. For a description of our derivative transactions, please read “Item 1. Business— Operations—Price Risk and Interest Rate Management Activities” and “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

(2) For an explanation of Standardized Measure, please see “Supplemental Oil and Natural Gas Information” in the Notes to the Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” of this Annual Report.

(3) Oil and natural gas prices are based on spot prices per Bbl and MMBtu, respectively, calculated using the 12-month unweighted average of first-day-of-the-month commodity prices (the “12-month average price”) for January through December 2014, with these representative prices adjusted by field for quality, transportation fees

and regional price differentials to arrive at the appropriate net price. NGLs prices were calculated using the differentials to the WTI price per Bbl of $94.87.

The following table sets forth information regarding net production of oil, natural gas and NGLs and certain price and cost information for each of the periods indicated. Information for fields with greater than 15% of our total proved reserves have been listed separately in the table below for the year ended December 31, 2014. None of our fields had proved reserves that were greater than 15% of our total proved reserves during 2013 and 2012.

	Net Production(1)			Average Realized Sales Prices (2)			Production Cost (3)
	Crude Oil Bbls/day	Natural Gas Mcf/day	NGLs Bbls/day	Crude Oil Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl	Per Mcfe
Year Ended December 31, 2014							
Pinedale (Green River Basin)	659	72,090	3,028	$77.76	$3.96	$13.76	$ 0.43
Mamm Creek (Piceance Basin)	288	32,455	1,424	$72.85	$3.33	$25.71	$ 0.71
All other fields	8,096	122,953	3,107	$83.66	$3.27	$37.14	$ 1.54
Total	9,043	227,498	7,559	$82.88	$3.50	$25.62	$ 1.11
Year Ended December 31, 2013							
All fields	8,462	137,632	4,047	$82.26	$3.39	$33.76	$ 1.36
Year Ended December 31, 2012							
All fields	7,536	53,695	1,813	$84.00	$4.47	$45.11	$ 1.85

(1) Average daily production for 2014 and 2013 calculated based on 365 days and for 2012 calculated based on 366 days including production for all of our acquisitions from the closing dates of these acquisitions.

(2) Average realized sales prices include the impact of hedges but exclude the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period. The average realized prices also reflect deductions for gathering, transportation and processing fees. For details on average sales prices without giving effect to the impact of hedges please see “Item 7. Management Discussion and Analysis of Financial Condition-Year Ended December 31, 2014 compared to Year Ended December 31, 2013” and “Item 7. Management Discussion and Analysis of Financial Condition -Year Ended December 31, 2013 compared to Year Ended December 31, 2012.”

(3) Production costs include such items as lease operating expenses and exclude production taxes (severance and ad valorem taxes).

Non-GAAP Financial Measure

Adjusted EBITDA

We present Adjusted EBITDA in addition to our reported net income (loss) attributable to Vanguard unitholders in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net income (loss) attributable to Vanguard unitholders plus, for 2011, net income (loss) attributable to the non-controlling interest. The result is net income (loss) which includes the non-controlling interest for 2011. From this we add or subtract the following:

- Net interest expense, including write-off of deferred financing fees;
- Depreciation, depletion, amortization and accretion;
- Impairment of oil and natural gas properties;
- Net gains or losses on commodity derivative contracts;
- Cash settlements on matured commodity derivative contracts;
- Net gains or losses on interest rate derivative contracts;
- Net gains and losses on acquisitions of oil and natural gas properties;
- Texas margin taxes;

- Compensation related items, which include unit-based compensation expense, unrealized fair value of phantom units granted to officers and cash settlement of phantom units granted to officers;
- Transaction costs incurred on acquisitions and mergers;
- Interest income;
- For 2011, non-controlling interest amounts attributable to each of the items above from the beginning of year through the completion of the ENP Merger on December 1, 2011, which revert the calculation back to an amount attributable to the Vanguard unitholders; and
- For 2011, administrative services fees charged to ENP, excluding the non-controlling interest, which are eliminated in consolidation.

Adjusted EBITDA is a significant performance metric used by management as a tool to measure (prior to the establishment of any cash reserves by our board of directors, debt service and capital expenditures) the cash distributions we could pay our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our monthly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and our operating performance and return on capital as compared to those of other companies in our industry.

Our Adjusted EBITDA should not be considered as an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies. For example, we fund premiums paid for derivative contracts, acquisitions of oil and natural gas properties, including the assumption of derivative contracts related to these acquisitions, and other capital expenditures primarily with proceeds from debt or equity offerings or with borrowings under our Reserve-Based Credit Facility. For the purposes of calculating Adjusted EBITDA, we consider the cost of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investments related to our underlying oil and natural gas properties; therefore, they are not deducted in arriving at our Adjusted EBITDA. Our Consolidated Statements of Cash Flows, prepared in accordance with GAAP, present cash settlements on matured derivatives and the initial cash outflows of premiums paid to enter into derivative contracts as operating activities. When we assume derivative contracts as part of a business combination, we allocate a part of the purchase price and assign them a fair value at the closing date of the acquisition. The fair value of the derivative contracts acquired is recorded as a derivative asset or liability and presented as cash used in investing activities in our Consolidated Statements of Cash Flows. As the volumes associated with these derivative contracts, whether we entered into them or we assumed them, are settled, the fair value is recognized in operating cash flows. Whether these cash settlements on derivatives are received or paid, they are reported as operating cash flows which may increase or decrease the amount we have available to fund distributions.

As noted above, for purposes of calculating Adjusted EBITDA, we consider both premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities. This is similar to the way the initial acquisition or development costs of our oil and natural gas properties are presented in our

Consolidated Statements of Cash Flows; the initial cash outflows are presented as cash used in investing activities, while the cash flows generated from these assets are included in operating cash flows. The consideration of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities for purposes of determining our Adjusted EBITDA differs from the presentation in our consolidated financial statements prepared in accordance with GAAP which (i) presents premiums paid for derivatives entered into as operating activities and (ii) the fair value of derivative contracts acquired as part of a business combination as investing activities.

The following table presents a reconciliation of our consolidated net income (loss) to Adjusted EBITDA.

	Year Ended December 31,				
	2014	2013	2012	2011[d]	2010[e]
	(in thousands)				
Net income (loss) attributable to Vanguard unitholders	$64,345	$59,511	$(168,815)	$62,063	$21,885
Net income attributable to non-controlling interest	—	—	—	26,067	—
Net income (loss)	64,345	59,511	(168,815)	88,130	21,885
Plus:					
Interest expense	69,765	61,148	41,891	28,994	5,766
Depreciation, depletion, amortization and accretion	226,937	167,535	104,542	84,857	22,231
Impairment of oil and natural gas properties	234,434	—	247,722	—	—
Net gains on commodity derivative contracts	(163,452)	(11,256)	(36,846)	(6,735)	(7,797)
Net cash settlements received on matured commodity derivative contracts [a][b]	10,187	30,905	39,102	18,720	25,887
Net losses on interest rate derivative contracts [c]	1,933	96	6,992	4,962	2,148
Net (gain) loss on acquisitions of oil and natural gas properties	(34,523)	(5,591)	(11,111)	367	5,680
Texas margin taxes	(630)	601	239	261	(12)
Compensation related items	11,710	5,931	6,796	3,026	1,026
Transaction costs incurred on acquisitions and mergers	739	865	—	2,019	3,583
Less:					
Interest income	—	—	—	—	(1)
Adjusted EBITDA before non-controlling interest	$421,445	$309,745	$230,512	$224,601	$80,396
Non-controlling interest attributable to adjustments above	—	—	—	(62,838)	—
Administrative services fees eliminated in consolidation	—	—	—	2,840	—
Adjusted EBITDA attributable to Vanguard unitholders	$421,445	$309,745	$230,512	$164,603	$80,396

(a) Excludes premiums paid, whether at inception or deferred, for derivative contracts that settled during the period. We consider the cost of premiums paid for derivatives as an investment related to our underlying oil and natural gas properties.	$—	$220	$11,641	$11,346	$1,950
(b) Excludes the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period. We consider the amounts paid to sellers for derivative contracts assumed with business combinations a part of the purchase price of the underlying oil and natural gas properties.	$21,306	$30,200	$26,505	$169	$1,995
	$4,035	$3,888	$2,515	$2,874	$1,799

(c) Includes settlements paid on interest rate
derivatives
(d) Results of operations from oil and natural gas properties acquired in the ENP Purchase through the date of the completion of the ENP Merger on December 1, 2011 were subject to a 53.4% non-controlling interest.
(e) As the ENP Purchase was completed on December 31, 2010, no results of operations were included for the year ended December 31, 2010.

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

The following discussion and analysis should be read in conjunction with "Item 6. Selected Financial Data" and the accompanying financial statements and related notes included elsewhere in this Annual Report. The following discussion contains forward-looking statements that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly in "Item 1A . Risk Factors" and "Forward Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increase our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, as of December 31, 2014, we own properties and oil and natural gas reserves primarily located in nine operating basins:

- the Green River Basin in Wyoming;
- the Piceance Basin in Colorado;
- the Permian Basin in West Texas and New Mexico;
- the Gulf Coast Basin in Texas, Louisiana and Mississippi;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Williston Basin in North Dakota and Montana;
- the Wind River Basin in Wyoming; and
- the Powder River Basin in Wyoming.

At December 31, 2014, we owned working interests in 9,759 gross (3,664 net) productive wells. In addition to these productive wells, we own leasehold acreage allowing us to drill new wells. We own working interests in approximately 870,140 gross undeveloped acres surrounding our existing wells. Approximately 32% or 653.7 Bcfe of our estimated proved reserves were attributable to our working interests in undeveloped leasehold acreage.

Recent Developments and Outlook

Historically, the markets for oil and natural gas have been very volatile and multiple factors during the latter half of 2014 have caused the price of oil and natural gas to decrease dramatically. Among the factors causing such volatility are the domestic oversupply of natural gas and the foreign supply of oil, the ability of the members of OPEC and other producing countries to agree upon and maintain prices and production levels, social unrest and instability, particularly in major oil and natural gas producing regions outside the United States and the level of consumer product demand.

Natural gas and oil prices are likely to continue to be volatile in the future, especially given current geopolitical and economic conditions. For example, the crude oil spot price per barrel during the year ended December 31, 2014 ranged from a high of $107.95 to a low of $53.45 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2014 and December 31, 2014 ranged from a high of $6.15 to a low of $2.89. As of February 23, 2015, the crude oil spot price per barrel was $49.56 and the NYMEX natural gas spot price per MMBtu was $2.88. The high to low oil price fluctuation during the year ended December 31, 2014 represents the second largest decline in one year in the past nine years.

The dramatic decline in commodity prices has had an impact on our unit price. During 2014, our common unit price fluctuated from a closing high of $32.95 on July 25, 2014 to a closing low of $13.59 on December 15, 2014. This low commodity price environment has had and will continue to have a direct impact on our revenue, cash flow from operations and Adjusted EBITDA until commodity prices improve. We intend to improve our financial outlook through opportunistic hedging and profitable drilling and acquiring new oil and natural gas properties. We foresee significant long term benefits in acquiring assets in this low price commodity environment.

Recently, we have taken steps to restructure our hedge portfolio to limit further downside and volatility due to the current commodity price environment. Specifically, we have converted a significant portion of our three-way collars in 2015 to fixed-price swaps or lowered the pricing on existing short puts. We have implemented a hedging program for approximately 77% and 45% of our anticipated crude oil production in 2015 and 2016, respectively, with 88% in the form of fixed-price swaps in 2015. Approximately 82% and 67% of our natural gas production in 2015 and 2016, respectively, is hedged with 98% in the form of fixed-price swaps in 2015. NGLs production is under fixed-price swaps for approximately 9% of anticipated production in 2015.

During 2015, we intend to concentrate our drilling on low risk, development opportunities with the majority of drilling capital focused on high Btu natural gas wells in two areas which we believe will continue to offer attractive drilling returns even in this low commodity price environment. We currently anticipate a capital budget for 2015 of approximately $113.5 million, excluding any potential future acquisitions, which is 20% less than our total spent in 2014. We expect to spend approximately 50% of the 2015 capital budget on activities in the Green River Basin where we will participate as a non-operated partner in the drilling and completion of vertical natural gas wells. Additionally, we expect to spend approximately 25% of the 2015 capital budget in the Gulf Coast Basin on the newly acquired East Haynesville assets drilling both vertical and horizontal wells and several recompletion projects. The balance of the 2015 budget is related to maintenance activities in our other operating areas. Due to our reduced capital spending in 2015and the assumed ethane rejection beginning in 2015 on our assets acquired in the Pinedale Acquisition in the Green River Basin, we anticipate our annual production will be slightly lower than our fourth quarter 2014 average daily production of 402,164 Mcfe per day.

We have reduced our cash distribution per common unit to $0.1175 for the month of January 2015, or $1.41 per unit on an annualized basis. This amount will be payable on March 17, 2015, to unitholders of record at the close of business on March 2, 2015, and represents a reduction from the payment for the month of December 2014, which was $0.21 per common unit or $2.52 per unit on an annualized basis. This new distribution rate takes into consideration current commodity and financial market conditions and helps to preserve our liquidity for potential future acquisition opportunities.

At February 27, 2014, we had indebtedness under our Reserve-Based Credit facility totaling $1.36 billion with a borrowing base of $2.0 billion which provided for $634.5 million in undrawn capacity, after consideration of a $5.5 million reduction in availability for letters of credit. Our next borrowing base redetermination is scheduled for April 2015 and based on projected market conditions and lower commodity prices, we currently expect that we will not be in compliance with our debt to Adjusted EBITDA covenant in certain future periods. We have been in discussions with certain banks in our credit facility regarding amending our debt to Adjusted EBITDA covenant during our next scheduled borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted Adjusted EBITDA due to lower commodity prices. We expect a reduction in our borrowing base at the next redetermination as a result of continued declines in oil and natural gas prices. The precise amount of the reduction is not known at this time but we do expect that we will have ample liquidity to manage our operations after the reduction. However, if necessary, we believe we have access to capital markets and other financing sources.

We recorded a non-cash ceiling test impairment of oil and natural gas properties for the year ended December 31, 2014 of $234.4 million as a result of a decline in realized oil and natural gas prices at the measurement date, December 31, 2014. Such impairment was recognized during the fourth quarter of 2014. The most significant factor affecting the 2014 impairment is related to the properties that we acquired in the Piceance Acquisition. The fair value of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) were higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. The fourth quarter 2014 impairment was calculated based on prices of $4.36 per MMBtu for natural gas and $94.87 per barrel of crude oil.

We expect to record an additional impairment of our oil and natural gas properties during 2015 as a result of declining oil and natural gas prices. Based on the 11-month average oil, natural gas and NGLs prices through February 1, 2015 and if such prices do not change during March 2015, we estimate that, on a pro forma basis, we will record a ceiling test write down on our existing assets of approximately $530.9 million at March 31, 2015 and an additional write down of $562.4 million for the remainder of the year ending December 31, 2015. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, natural gas and NGLs for the remainder of 2015, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and natural gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

While no goodwill impairment was recognized at December 31, 2014, any further significant decline in prices of oil and natural gas or significant negative reserve adjustments could change our estimate of the fair value of the reporting unit and could result in an impairment charge.

Results of Operations

The following table sets forth selected financial and operating data for the periods indicated.

	Year Ended December 31, (1)		
	2014	2013	2012
	(in thousands)		
Revenues:			
Oil sales	$268,685	$268,922	$233,153
Natural gas sales	285,439	124,513	47,270
NGLs sales	70,489	49,813	29,933
Oil, natural gas and NGLs sales	624,613	443,248	310,356
Net gains on commodity derivative contracts	163,452	11,256	36,846
Total revenues	$788,065	$454,504	$347,202
Costs and expenses:			
Lease operating expenses	132,515	105,502	74,366
Production and other taxes	61,874	40,430	29,369
Depreciation, depletion, amortization and accretion	226,937	167,535	104,542
Impairment of oil and natural gas properties	234,434	—	247,722
Selling, general and administrative expenses (excluding non-cash compensation)	19,129	20,011	17,045
Non-cash compensation	11,710	5,931	5,421
Total costs and expenses	$686,599	$339,409	$478,465
Other income and expenses:			
Interest expense	$(69,765)	$(61,148)	$(41,891)
Net losses on interest rate derivative contracts	$(1,933)	$(96)	$(6,992)
Net gain on acquisitions of oil and natural gas properties	$34,523	$5,591	$11,111
Other income	$54	$69	$220

(1) From 2012 through 2014, we acquired certain oil and natural gas properties and related assets, as well as additional interests in these properties. The operating results of these properties are included with ours from the date of acquisition forward.

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

Revenues

Oil, natural gas and NGLs sales increased $181.4 million to $624.6 million during the year ended December 31, 2014 as compared to the same period in 2013. The key revenue measurements were as follows:

	Year Ended December 31, (1) 2014	2013	Percentage Increase (Decrease)
Average realized prices, excluding hedging:			
Oil (Price/Bbl)	$81.40	$87.06	(7)%
Natural Gas (Price/Mcf)	$3.44	$2.48	39%
NGLs (Price/Bbl)	$25.55	$33.72	(24)%
Average realized prices, including hedging (2):			
Oil (Price/Bbl)	$82.88	$82.26	1%
Natural Gas (Price/Mcf)	$3.50	$3.39	3%
NGLs (Price/Bbl)	$25.62	$33.76	(24)%
Average NYMEX prices:			
Oil (Price/Bbl)	$92.21	$98.04	(6)%
Natural Gas (Price/Mcf)	$4.39	$3.66	20%
Total production volumes:			
Oil (MBbls)	3,301	3,089	7%
Natural Gas (MMcf)	83,037	50,236	65%
NGLs (MBbls)	2,759	1,477	87%
Combined (MMcfe)	119,395	77,630	54%
Average daily production volumes:			
Oil (Bbls/day)	9,043	8,462	7%
Natural Gas (Mcf/day)	227,498	137,632	65%
NGLs (Bbls/day)	7,559	4,047	87%
Combined (Mcfe/day)	327,109	212,686	54%

(1) During 2014 and 2013, we acquired certain oil and natural gas properties and related assets, as well as additional interests in these properties. The operating results of these properties are included with ours from the date of acquisition forward.

(2) Excludes the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period.

The increase in oil, natural gas and NGLs sales during the year ended December 31, 2014 compared to the same period in 2013 was primarily due to the increase in production from our acquisitions that were completed during 2014. Natural gas revenues increased from $124.5 million during the year ended December 31, 2013 to $285.4 million during the same period in 2014 primarily as a result of a 32,801 MMcf increase in our natural gas production volumes. In addition, we also had a 39% increase in our average realized natural gas sales price received, excluding hedges, due to a higher average NYMEX price, which increased from $3.66 per Mcf during the year ended December 31, 2013 to

$4.39 per Mcf during the same period in 2014. Oil revenues decreased by $0.2 million from $268.9 million during the year ended December 31, 2013 to $268.7 million during the same period in 2014 primarily due to a $5.66 decrease in our average realized oil price, excluding hedges, mainly resulting from the decrease in average NYMEX price from $98.04 per Bbl during the year ended December 31, 2013 to $92.21 during the same period in 2014. The impact of the decrease in average realized price was slightly offset by a 212 MBbls increase in oil production volumes in 2014 compared to the prior year. NGLs revenues also increased 42% in 2014 compared to the same period in 2013 primarily due to a 1,282 MBbls increase in NGLs production volumes, offset by an $8.17 per Bbl, or 24%, decrease in our average realized NGLs price, excluding hedges.

Overall, our total production increased by 54% on an Mcfe basis for the year ended December 31, 2014 over the comparable period in 2013, which was primarily attributable to the impact from all of our acquisitions completed in 2013 wherein we realized the benefit of a full year of production in 2014 as well as from our 2014 acquisitions. On an Mcfe basis, crude oil, natural gas and NGLs accounted for 16%, 70% and 14%, respectively, of our production during the year ended December 31, 2014 compared to crude oil, natural gas and NGLs of 24%, 65% and 11%, respectively, during the same period in 2013.

Hedging and Price Risk Management Activities

During the year ended December 31, 2014, we recognized a $163.5 million net gain on commodity derivative contracts. Net cash settlements on matured commodity derivative contracts of $10.2 million were received during the period. Our hedging program is intended to help mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and we pay the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because our hedges are currently not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected in our consolidated statement of operations in the net gains or losses on commodity derivative contracts line item. However, these fair value changes that are reflected in the consolidated statement of operations reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and again the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by $27.0 million to $132.5 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013, of which $31.1 million was related to increased lease operating expenses for oil and natural gas properties acquired in 2014 and 2013. The increase was partially offset by a $4.1 million decrease in maintenance and repair expenses on existing wells.

Production and other taxes include severance, ad valorem and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state and county and are based on the value of our reserves. Production and other taxes increased by $21.4 million to $61.9 million for the year ended December 31, 2014 primarily due to higher wellhead revenues as a result of the acquisitions completed in 2014. As a percentage of wellhead revenues, production, severance, and ad valorem taxes increased from 9.1% during the year ended December 31, 2013 to 9.9% for the year ended December 31, 2014 primarily due to higher tax rates on properties acquired during 2014 in the state of Wyoming and a lower tax rate in 2013 primarily due to an accrued refund from the state of Texas for overpaid severance taxes on oil and natural gas properties in Texas pertaining to marketing cost reductions and tax reimbursements.

Depreciation, depletion, amortization and accretion increased to approximately $226.9 million for the year ended December 31, 2014 from approximately $167.5 million for the year ended December 31, 2013 primarily due to a higher depletion base associated with properties acquired during 2013 and 2014.

An impairment of oil and natural gas properties of $234.4 million was recognized during the year ended December 31, 2014 as a result of a decline in realized oil and natural gas prices at the measurement date, December 31, 2014. Such impairment was recognized during the fourth quarter of 2014. The most significant factor affecting the 2014 impairment related to the properties that we acquired in the Piceance Acquisition. The fair value of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) was higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. The fourth quarter 2014 impairment was calculated based on prices of $4.36 per MMBtu for natural gas and $94.87 per barrel of crude oil.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the year ended December 31, 2014 decreased $0.9 million as compared to the year ended December 31, 2013 primarily resulting from the change in the accrual of executive and employee bonuses of about $4.3 million, which were recorded as non-cash compensation in the current year as these will be paid in Company common units as compared to being paid in cash, offset by an increase of about $3.4 million resulting from the hiring of additional employees and payments for transition fees related to our acquisitions. In addition to the increase in non-cash compensation resulting from paying 2014 bonuses in Company common units, we also recognized $1.5 million of additional expenses resulting from restricted and phantom unit grants in 2014.

Other Income and Expense

Interest expense increased to $69.8 million for the year ended December 31, 2014 as compared to $61.1 million for the year ended December 31, 2013 primarily due to a higher average outstanding debt under our Reserve-Based Credit Facility in 2014 compared to the same period in 2013.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the acquisitions completed during 2014 compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $34.9 million and in goodwill of $0.4 million, which was immediately impaired and recorded as a loss, resulting in a net gain of $34.5 million for the year ended December 31, 2014. The comparable measurement for the acquisitions completed during 2013 resulted in a gain of $7.3 million and in goodwill of $1.7 million, which was immediately impaired and recorded as a loss, resulting in a net gain of $5.6 million for the year ended December 31, 2013. The net gains and losses resulted from the increases and decreases in oil and natural gas prices used to value the reserves between the commitment and close dates and have been recognized in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations.

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

Revenues

Oil, natural gas and NGLs sales increased by $132.9 million to $443.2 million during the year ended December 31, 2013 as compared to the same period in 2012. The key revenue measurements were as follows:

	Year Ended December 31, (1) 2013	2012 (2)	Percentage Increase (Decrease)	
Average realized prices, excluding hedging:				
Oil (Price/Bbl)	$87.06	$84.53	3	%
Natural Gas (Price/Mcf)	$2.48	$2.41	3	%
NGLs (Price/Bbl)	$33.72	$45.11	(25	)%
Average realized prices, including hedging (3):				
Oil (Price/Bbl)	$82.26	$84.00	(2	)%
Natural Gas (Price/Mcf)	$3.39	$4.47	(24	)%
NGLs (Price/Bbl)	$33.76	$45.11	(25	)%
Average NYMEX prices:				
Oil (Price/Bbl)	$98.04	$94.19	4	%
Natural Gas (Price/Mcf)	$3.66	$2.96	24	%
Total production volumes:				
Oil (MBbls)	3,089	2,758	12	%
Natural Gas (MMcf)	50,236	19,652	156	%
NGLs (MBbls)	1,477	664	123	%
Combined (MMcfe)	77,630	40,183	94	%
Average daily production volumes:				
Oil (Bbls/day)	8,462	7,536	12	%
Natural Gas (Mcf/day)	137,632	53,695	156	%
NGLs (Bbls/day)	4,047	1,813	123	%
Combined (Mcfe/day)	212,686	109,789	94	%

(1) During 2013 and 2012, we acquired certain oil and natural gas properties and related assets, as well as additional interests in these properties. The operating results of these properties are included with ours from the date of acquisition forward.

(2) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

(3) Excludes the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period.

The increase in oil, natural gas and NGLs sales during the year ended December 31, 2013 compared to the same period in 2012 was primarily due to the increase in production from our acquisitions that were completed during 2012 and 2013. Natural gas revenues increased from $47.3 million during the year ended December 31, 2012 to $124.5 million during the same period in 2013 primarily as a result of a 30,584 MMcf increase in our natural gas production volumes from our acquisitions. In addition, we also had a 3% increase in our average realized natural gas sales price received, excluding hedges, due to a higher average NYMEX price, which increased from $2.96 per Mcf during the year ended December 31, 2012 to $3.66 per Mcf during the same period in 2013. The impact of the increase in production volumes was offset by a 24% decrease in our average realized natural gas price, including hedges, from $4.47 per Mcf in 2012 to $3.39 per Mcf in the same period of 2013, primarily due to a 14% decrease in our weighted average natural gas hedge price. Oil revenues increased by $35.8 million from $233.2 million during the year ended December 31, 2012 to $268.9 million during the same period in 2013 primarily as a result of a 331 MBbls increase in our oil production. In addition, we also realized a higher average oil price, excluding hedges, due to the increase in average NYMEX price from $94.19 per Bbl during the year ended December 31, 2012 to $98.04 during the same period in 2013. NGLs revenues also increased 66% in 2013 compared to the same period in 2012 primarily due to a 813 MBbls increase in NGLs production volumes, offset by an $11.39 per Bbl, or 25%, decrease in our average realized NGLs price, excluding hedges.

Overall, our total production increased by 94% on an Mcfe basis for the year ended December 31, 2013 over the comparable period in 2012 and was primarily attributable to the impact from all of our acquisitions completed in 2012 wherein we realized the benefit of a full year of production in 2013 as well as from our 2013 acquisitions. On an Mcfe basis, crude oil, natural gas and NGLs accounted for 24%, 65% and 11%, respectively, of our production during the year ended December 31, 2013 compared to crude oil, natural gas and NGLs of 41%, 49% and 10%, respectively, during the same period in 2012.

Hedging and Price Risk Management Activities

During the year ended December 31, 2013, we recognized an $11.3 million net gain on commodity derivative contracts. Net cash settlements on matured commodity derivative contracts of $30.9 million were received during the period. Our hedging program is intended to help mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and we pay the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because our hedges are currently not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected in our consolidated statement of operations in the net gains or losses on commodity derivative contracts line item. However, these fair value changes that are reflected in the consolidated statement of operations reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and again the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel, and other customary charges. Lease operating expenses increased by $31.1 million to $105.5 million for the year ended December 31, 2013 as compared to the year ended December 31, 2012, of which $29.9 million was related to increased lease operating expenses for oil and natural gas properties acquired during the second half of 2012 and in 2013, and $1.2 million was related to increased maintenance and repair expenses on existing wells.

Production and other taxes include severance, ad valorem and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state and county and are based on the value of our reserves. Production and other taxes increased by $11.1 million to $40.4 million for the year ended December 31, 2013 primarily due to higher wellhead revenues as a result of the acquisitions completed in the second half of 2012 and in 2013. As a percentage of wellhead revenues, production, severance, and ad valorem taxes slightly decreased from 9.5% during the year ended December 31, 2012 to 9.1% for the year ended December 31, 2013.

Depreciation, depletion, amortization and accretion increased to approximately $167.5 million for the year ended December 31, 2013 from approximately $104.5 million for the year ended December 31, 2012 due primarily to the increase in oil and natural gas properties related to all our acquisitions completed during the second half of 2012 and in 2013.

An impairment of oil and natural gas properties of $247.7 million was recognized during the year ended December 31, 2012 as a result of a decline in natural gas prices at the measurement dates, September 30, 2012 and December 31, 2012. Such impairment was recognized during the third and fourth quarters of 2012. The most significant factor affecting the 2012 impairment related to the properties that we acquired in the Arkoma Basin, the Piceance Basin, the Wind River Basin and the Powder River Basin. The fair values of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) were higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. We were able to lock in the higher prices at the time of the acquisitions for 100% of the estimated natural gas production through June 2017 for the properties acquired in the Arkoma Basin and 85% of the estimated natural gas production through December 2016 for the properties acquired in the Piceance Basin, the Wind River Basin and the Powder River Basin by using commodity derivative contracts. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. The third quarter impairment was calculated based on prices of $2.77 per MMBtu for natural gas and $95.26 per barrel of crude oil while the fourth quarter impairment was calculated based on prices of $2.76 per MMBtu for natural gas and $94.67 per barrel of crude oil. There was no impairment of oil and natural gas properties recognized during the year ended December 31, 2013.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the year ended December 31, 2013 increased $3.0 million as compared to the year ended December 31, 2012 primarily resulting from increased compensation of $2.4 million related expenses resulting from the hiring of additional employees and increased executive compensation, $0.4 million in transition fees related to one of our acquisitions, and approximately $0.2 million increase in other general and administrative expenses attributable to our growth. Non-cash compensation expense also increased $0.5 million in 2013 as compared to the year ended December 31, 2012 primarily related to additional restricted and phantom unit grants in 2013.

Other Income and Expense

Interest expense increased to $61.1 million for the year ended December 31, 2013 as compared to $41.9 million for the year ended December 31, 2012 primarily due to a higher interest rate as a result of our public debt offerings completed in 2012.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the acquisitions completed during 2013 compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $7.3 million and in goodwill of $1.7 million, which was immediately impaired and recorded as a loss, resulting in a net gain of $5.6 million for the year ended December 31, 2013. The comparable measurement for the acquisitions completed during 2012 resulted in goodwill of $9.1 million, which was immediately impaired and recorded as a loss, and a gain of $20.2 million, resulting in a net gain of $11.1 million for the year ended December 31, 2012. The net gains and losses resulted from the increases and decreases in oil and natural gas prices used to value the reserves between the commitment and close dates and have been recognized in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements.

Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We have discussed the development, selection and disclosure of each of these with our audit committee. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. Please read Note 1 to the Notes to the Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” of this Annual Report for a discussion of additional accounting policies and estimates made by management.

Full-Cost Method of Accounting for Oil and Natural Gas Properties

The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for gas and oil business activities: the successful-efforts method and the full-cost method. There are several significant differences between these methods. Under the successful-efforts method, costs such as geological and geophysical, exploratory dry holes and delay rentals are expensed as incurred, where under the full-cost method these types of charges would be capitalized to the full-cost pool. In the measurement of impairment of proved gas and oil properties, the successful-efforts method of accounting follows the guidance provided in ASC Topic 360, “Property, Plant and Equipment,” where the first measurement for impairment is to compare the net book value of the related asset to its undiscounted future cash flows using commodity prices consistent with management expectations. Under the full-cost method, the net book value (full-cost pool) is compared to the future net cash flows discounted at 10% using commodity prices based upon the 12-month average price (ceiling limitation). If the full-cost pool is in excess of the ceiling limitation, the excess amount is charged as an expense.

We have elected to use the full-cost method to account for our investment in oil and natural gas properties. Under this method, we capitalize all acquisition, exploration and development costs for the purpose of finding oil, natural gas and NGLs reserves, including salaries, benefits and other internal costs directly related to these finding activities. For the years ended December 31, 2014 and 2013, there were no internal costs capitalized. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. In addition, gains or losses on the sale or other disposition of oil and natural gas properties are not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Our results of operations would have been different had we used the successful-efforts method for our oil and natural gas investments. Generally, the application of the full-cost method of accounting results in higher capitalized costs and higher depletion rates compared to similar companies applying the successful-efforts method of accounting.

Full-Cost Ceiling Test

At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties is limited to the sum of the estimated future net revenues from proved properties using oil and natural gas prices based upon the 12-month average prices, after giving effect to cash flow hedge positions, for which hedge accounting is applied, discounted at 10% and the lower of cost or fair value of unproved properties (“Ceiling Test”). Our hedges are not considered cash flow hedges for accounting purposes, and thus the value of our hedges are not considered in our ceiling test calculations. The SEC’s Final Rule, “Modernization of Oil and Gas Reporting,” requires that the present value of future net revenue from proved properties be calculated based upon the 12-month average price.

The calculation of the Ceiling Test and the provision for depletion and amortization are based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development as more fully discussed in “—Oil, Natural Gas and NGLs Reserve Quantities” below. Due to the imprecision in estimating oil, natural gas and NGLs reserves as well as the potential volatility in oil, natural gas and NGLs prices and their effect on the carrying value of our proved oil, natural gas and NGLs reserves, there can be no assurance that additional Ceiling Test write downs in the future will not be required as a result of factors that may negatively affect the present value of proved oil and natural gas properties. These factors include declining oil, natural gas and NGLs prices, downward revisions in estimated proved oil, natural gas and NGLs reserve quantities and unsuccessful drilling activities.

We recorded a non-cash ceiling test impairment of oil and natural gas properties for the year ended December 31, 2014 of $234.4 million as a result of a decline in realized oil and natural gas prices at the measurement date, December 31, 2014. Such impairment was recognized during the fourth quarter of 2014. The most significant factor affecting the 2014 impairment related to the properties that we acquired in the Piceance Acquisition. The fair value of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) was higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. The fourth quarter 2014 impairment was calculated based on prices of $4.36 per MMBtu for natural gas and $94.87 per barrel of crude oil. No ceiling test impairment was required during 2013.

During the year ended December 31, 2012, we recorded a non-cash ceiling test impairment of oil and natural gas properties of $247.7 million as a result of a decline in natural gas prices at the measurement dates, September 30, 2012 and December 31, 2012. Such impairment was recognized during the third and fourth quarters of 2012. The most significant factor affecting the 2012 impairment related to the properties that we acquired in the Arkoma Basin and the properties acquired in the Piceance Basin, the Wind River Basin and the Powder River Basin. The fair values of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) were higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. We were able to lock in the higher prices at the time of the acquisitions for 100% of the estimated natural gas production through June 2017 for the properties acquired in the Arkoma Basin Acquisition and 85% of the estimated natural gas production through December 2016 for the properties acquired in the Piceance Basin, the Wind River Basin and the Powder River Basin by using commodity derivative contracts. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. The third quarter impairment was calculated based on prices of $2.77 per MMBtu for natural gas and $95.26 per barrel of crude oil while the fourth quarter impairment was calculated based on prices of $2.76 per MMBtu for natural gas and $94.67 per barrel of crude oil.

In accordance with the guidance contained within ASC Topic 805, upon the acquisition of oil and natural gas properties, the company records an asset based on the measurement of the fair value of the properties acquired determined using forward oil and natural gas price curves at the acquisitions dates, which can have several price increases over the entire reserve life. As discussed above, capitalized oil and natural gas property costs are limited to a ceiling based on the present value of future net revenues, computed using a flat price for the entire reserve life equal to the historical 12-month average price, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is less than the total capitalized costs, we are required to write down capitalized costs to the ceiling. As a result, there is a risk that we will be required to record an impairment of our oil and natural gas properties if certain attributes exist, such as declining oil and natural gas prices. We expect to record an additional impairment of our oil and natural gas properties during 2015 as a result of declining oil and natural gas prices. Based on the 11-month average oil, natural gas and NGLs prices through February 1, 2015 and if such prices do not change during March 2015, we estimate that, on a pro forma basis, we will record a ceiling test write down on our existing assets of approximately $530.9 million at March 31, 2015 and an additional write down of $562.4 million for the remainder of the year ending December 31, 2015. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, natural gas and NGLs for the remainder of 2015, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and natural gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

Business Combinations

We account for business combinations under ASC Topic 805. We recognize and measure in our financial statements the fair value of all identifiable assets acquired, the liabilities assumed, any non-controlling interests in the acquiree and any goodwill acquired in all transactions in which control of one or more businesses is obtained.

Goodwill and Other Intangible Assets

We account for goodwill and other intangible assets under the provisions of the Accounting Standards Codification (ASC) Topic 350, “Intangibles-Goodwill and Other.” Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is not amortized, but is tested for impairment annually on October 1 or whenever indicators of impairment exist using a two-step process. The goodwill test is performed at the reporting unit level, which represents our oil and natural gas operations in the United States. The first step involves a comparison of the estimated fair value of a reporting unit to its net book value, which is its carrying amount, including goodwill. In performing the first step, we determine the fair value of the reporting unit using the market approach. Determining fair value requires the exercise of significant judgment, including judgments about market prices and other relevant information generated by market transactions involving identical or comparable assets, liabilities, or a group of assets and liabilities, such as a business. If the estimated fair value of the reporting unit exceeds its net book value, goodwill of the reporting unit is not impaired and the second step of the impairment test is not necessary. If the net book value of the reporting unit exceeds its fair value, the second step of the goodwill impairment test will be performed to measure the amount of impairment loss, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit’s goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. In other words, the estimated fair value of the reporting unit is allocated to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination and the fair value of the reporting unit was the purchase price paid. If the carrying amount of the reporting unit’s goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess.

We performed our annual impairment tests during 2014, 2013 and 2012 and our analyses concluded that there was no impairment of goodwill as of these dates. However, due to the current decline in the prices of oil and natural gas as well as deteriorating market conditions, we performed an interim impairment test at December 31, 2014. Based on our estimates, the fair value of our reporting unit exceeded its carrying value by 8% at December 31, 2014 and therefore the second step of the impairment test was not necessary. We believe this difference between the fair value and the net book value is appropriate (in the context of assessing whether a goodwill impairment may exist) when a market-based control premium is taken into account and in light of the recent volatility in the equity markets.

While no goodwill impairment was recognized at December 31, 2014, any further significant decline in the prices of oil and natural gas or significant negative reserve adjustments could change our estimate of the fair value of the reporting unit and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. We evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

We allocate the purchase price paid for the acquisition of a business to the assets and liabilities acquired based on the estimated fair values of those assets and liabilities. Estimates of fair value are based upon, among other things, reserve estimates, anticipated future prices and costs, and expected net cash flows to be generated. These estimates are often highly subjective and may have a material impact on the amounts recorded for acquired assets and liabilities.

Asset Retirement Obligation

We have obligations to remove tangible equipment and restore land at the end of an oil or natural gas well's life. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and the decommissioning of our Elk Basin and Fairway gas plants. Estimating the future plugging and abandonment costs requires management to make estimates and judgments inherent in the present value calculation of the future obligation. These include ultimate plugging and abandonment costs, inflation factors, credit adjusted discount rates, and timing of the obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

Oil, Natural Gas and NGLs Reserve Quantities

Our reserve engineers estimate proved oil and gas reserves accordance with SEC regulations, which directly impact financial accounting estimates, including depreciation, depletion, amortization and accretion. Proved oil and gas reserves are defined by the SEC as the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Although our reserve engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates used by us. We cannot predict the types of reserve revisions that will be required in future periods.

Revenue Recognition

Sales of oil, natural gas and NGLs are recognized when oil, natural gas and NGLs have been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. We sell oil, natural gas and NGLs on a monthly basis. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions, so that the price of the oil, natural gas and NGLs fluctuates to remain competitive with other available oil, natural gas and NGLs supplies. As a result, our revenues from the sale of oil, natural gas and NGLs will suffer if market prices decline and benefit if they increase without consideration of hedging. We believe that the pricing provisions of our oil, natural gas and NGLs contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded.

The Company has elected the entitlements method to account for gas production imbalances. Gas imbalances occur when we sell more or less than our entitled ownership percentage of total gas production. Any amount received in excess of our share is treated as a liability. If we receive less than our entitled share the underproduction is recorded as a receivable. We did not have any significant gas imbalance positions at December 31, 2014 or 2013.

Price Risk Management Activities

We use derivative financial instruments to achieve a more predictable cash flow from our oil and natural gas production by reducing our exposure to price fluctuations. Currently, we primarily use fixed-price swaps, basis swap contracts and other hedge option contracts to hedge oil and natural gas prices.

Under ASC Topic 815 "Derivatives and Hedging" ("ASC Topic 815"), the fair value of hedge contracts is recognized in the Consolidated Balance Sheets as an asset or liability, and since we do not apply hedge accounting, the change in fair value of the hedge contracts are reflected in earnings. If the hedge contracts qualify for hedge accounting treatment, the fair value of the hedge contract is recorded in "accumulated other comprehensive income," and changes in the fair value do not affect net income until the contract is settled. If the hedge contract does not qualify for hedge accounting treatment, the change in the fair value of the hedge contract is reflected in earnings during the period as gain or loss on commodity derivatives.

Stock Based Compensation

We account for Stock Based Compensation pursuant to ASC Topic 718 "Compensation-Stock Compensation" ("ASC Topic 718"). ASC Topic 718 requires an entity to recognize the estimated grant-date fair value of stock options and other equity-based compensation issued to employees in the income statement. It establishes fair value as the measurement objective in accounting for share-based payment arrangements and requires all companies to apply a fair-value-based measurement method in accounting for generally all share-based payment transactions with employees.

Capital Resources and Liquidity

Overview

Historically, we have obtained financing through proceeds from bank borrowings, cash flow from operations and from the public equity and debt markets to provide us with the capital resources and liquidity necessary to operate our business. To date, the primary use of capital has been for the acquisition and development of oil and natural gas properties; however, we expect to distribute to unitholders a significant portion of our free cash flow. As we execute our business strategy, we will continually monitor the capital resources available to us to meet future financial obligations, planned capital expenditures, acquisition capital and distributions to our unitholders. Our future success in growing reserves, production and cash flow will be highly dependent on the capital resources available to us and our success in drilling for and acquiring additional reserves. We expect to fund our drilling capital expenditures and distributions to unitholders with cash flow from operations, while funding any acquisition capital expenditures that we might incur with borrowings under our Reserve-Based Credit Facility and publicly offered equity and debt, depending on market conditions. As of February 27, 2014, we have $634.5 million available to be borrowed under our Reserve-Based Credit Facility.

The borrowing base under our Reserve-Based Credit Facility is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the lenders' petroleum engineers utilizing the lenders' internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and NGLs reserves. Our current borrowing base is $2.0 billion. Based on projected market conditions and lower commodity prices, it is likely that banks will lower their internal projections of oil, natural gas and NGLs prices, and we expect that we will be subject to a decrease in our borrowing base availability in the future. We also currently expect that we will not be in compliance with our debt to Adjusted EBITDA covenant in certain future periods. We have been in discussions with certain banks in our Reserve-Based Credit Facility regarding amending our debt to Adjusted EBITDA covenant during our next scheduled borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted Adjusted EBITDA due to the lower commodity price environment. Our next borrowing base redetermination is scheduled for April 2015.

As a result, absent accretive acquisitions, to the extent available after unitholder distributions, debt service, and capital expenditures, it is our current intention to utilize our excess cash flow during 2015 to reduce our borrowings under our Reserve-Based Credit Facility. Based upon current expectations, we believe existing liquidity and capital resources will be sufficient for the conduct of our business and operations for the foreseeable future.

The following table summarizes our primary sources and uses of cash in each of the most recent three years:

	Year Ended December 31,		
	2014	2013	2012
	(in millions)		
Net cash provided by operating activities	$339.8	$261.0	$204.5
Net cash used in investing activities	$(1,446.2)	$(398.0)	$(839.2)
Net cash provided by financing activities	$1,094.6	$137.3	$643.5

Cash Flow from Operations

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Net cash provided by operating activities was $339.8 million during the year ended December 31, 2014, compared to $261.0 million during the year ended December 31, 2013, and compared to $204.5 million during the year ended December 31, 2012.

During the year ended December 31, 2014, changes in working capital decreased total cash flows by $10.6 million. Contributing to the decrease in working capital during 2014 was a $51.5 million increase in accounts payable and oil and natural gas revenue payable, accrued expenses and other current liabilities that resulted primarily from the timing effects of invoice payments, offset by a $69.9 million increase in accounts receivable related to the timing of receipts from production from the acquisitions.

During the year ended December 31, 2013, changes in working capital increased cash flows by $13.8 million. Contributing to the increase in working capital during 2013 was a $35.3 million increase in accounts payable and oil and natural gas revenue payable, accrued expenses and other current liabilities that resulted primarily from the timing effects of invoice payments, offset by a $22.1 million increase in accounts receivable related to the timing of receipts from production from the acquisitions.

During the year ended December 31, 2012, changes in working capital resulted in a $16.9 million increase in cash flows from operating activities due to a $23.0 million increase in accounts payable and oil and natural gas revenue payable, accrued expenses and other current liabilities that resulted primarily from the timing effects of invoice payments, a $3.8 million decrease in accounts receivable related to the timing of receipts from production from the acquisitions and offset by an $8.2 million payment for premiums paid commodity derivative contracts.

The change in the fair value of our derivative contracts are non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the years ended December 31, 2014, 2013 and 2012.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, natural gas and NGLs prices. Oil, natural gas and NGLs prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic and political activity, weather and other factors beyond our control. Future cash flow from operations will depend on our ability to maintain and increase production through our drilling program and acquisitions, as well as the prices of oil, natural gas and NGLs. We enter into derivative contracts to reduce the impact of commodity price volatility on operations. Currently, we primarily use fixed-price swaps, basis swap contracts and other hedge option contracts to hedge oil and natural gas prices. However, unlike natural gas, we are unable to hedge oil price differentials in certain operating areas which could significantly impact our cash flow from operations. Please read "Item 1. Business—Operations—Price Risk and Interest Rate Management Activities" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for details about derivatives in place through 2017 for oil and natural gas production and through 2015 for NGLs production.

Investing Activities

Cash used in investing activities was approximately $1.4 billion for the year ended December 31, 2014, compared to $398.0 million during 2013, and compared to $839.2 million during 2012.

Cash used in investing activities during the year ended December 31, 2014 included $1.3 billion for the acquisition of oil and natural gas properties, $142.0 million for the drilling and development of oil and natural gas properties, $5.2 million for deposits and prepayments related to the drilling and development of oil and natural gas properties and $1.4 million in payments for property and equipment. Also during the year, we received $5.0 million in proceeds from the divestiture of certain oil and natural gas properties and leases.

During the year ended December 31, 2013, we used cash of $272.1 million for the acquisition of oil and natural gas properties, $56.7 million for the drilling and development of oil and natural gas properties, $67.3 million for deposits and prepayments related to the drilling and development of oil and natural gas properties and $2.0 million for property and equipment additions.

During the year ended December 31, 2012, we used cash of $783.4 million for the acquisition of oil and natural gas properties, $50.4 million for the drilling and development of oil and natural gas properties, and $10.3 million for deposits and prepayments related to the drilling and development of oil and natural gas properties, offset by $5.5 million in proceeds from the partial sale of certain oil and natural gas leases in the Williston region.

Excluding any potential acquisitions, we currently anticipate a capital budget for 2015 of approximately $113.5 million. Our expected capital spending will largely include drilling and completion in the Green River Basin and the Gulf Coast Basin on the newly acquired East Haynesville assets, drilling both vertical and horizontal wells and several recompletion projects. We anticipate that our cash flow from operations and available borrowing capacity under our Reserve-Based Credit Facility will exceed our planned capital expenditures and other cash requirements for the year ended December 31, 2015. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Cash provided by financing activities was approximately $1.1 billion for year ended December 31, 2014, compared to $137.3 million for the year ended December 31, 2013 and compared to $643.5 million for the year ended December 31, 2012.

Cash provided by financing activities during the year ended December 31, 2014 included net proceeds from borrowings of long-term debt of $1.4 billion, net proceeds from our preferred unit offerings of $274.4 million and net proceeds from our common unit offerings of $147.8 million. Additionally, cash of $488.0 million was used in the repayments of our Reserve-Based Credit Facility, $2.5 million was used for the repurchase of common units under the buyback program and $1.2 million was paid for financing costs. We also paid distributions of $206.6 million to our common and Class B unitholders and $17.3 million to our preferred unitholders.

Cash provided by financing activities during the year ended December 31, 2013 included $589.5 million net proceeds from borrowings of long-term debt, $61.0 million net proceeds from our preferred unit offerings and $498.4 million net proceeds from our common unit offerings. Additionally, cash of $829.5 million was used in the repayments of our Reserve-Based Credit Facility, $2.1 million was paid for financing costs. We also paid $177.6 million in distributions to our common and Class B unitholders and $2.4 million in distributions to our preferred unitholders.

Cash provided by financing activities during the year ended December 31, 2012 included net proceeds from borrowings of long-term debt of $1.5 billion and $321.9 million in proceeds from our public equity offerings. Additionally, cash of $1.0 billion was used in the repayments of our Reserve-Based Credit Facility, $15.6 million was paid for financing costs and $140.3 million was paid to common unitholders in the form of distributions.

Shelf Registration Statements and Related Offerings

We have registered an indeterminate amount of Series A Cumulative Preferred Units, Series B Cumulative Preferred Units, Series C Cumulative Preferred Units, common units, debt securities and guarantees of debt securities under our shelf registration statement filed with the SEC (the “Shelf Registration Statement”), which was effective until January 2015. We filed a new shelf registration statement on February 13, 2015 to replace the expired shelf registration statement.

Net proceeds, terms and pricing of each offering of securities issued under the Shelf Registration Statement are determined at the time of such offerings. The Shelf Registration Statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the Shelf Registration Statement for the purpose of issuing, from time to time, any combination of equity or debt securities, will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.
We have entered into an equity distribution agreement with respect to the issuance and sale of our Series A Cumulative Preferred Units and common units (the “Equity Distribution Agreement”) under our at-the-market equity program. Pursuant to the terms of the equity distribution agreement, we may sell from time to time through our sales agents (i) our common units representing limited liability company interests having an aggregate offering price of up

to $500.0 million and (ii) our Series A Cumulative Preferred Units having an aggregate offering price of up to $250.0 million. The common units and Series A Cumulative Preferred Units to be sold under the Equity Distribution Agreement are registered under our existing Shelf Registration Statement. During the year ended December 31, 2014, total net proceeds received under our at-the-market equity program were approximately $147.8 million, after commissions and fees, from the sales of 4,863,690 common units and $1.2 million, after commissions and fees, from the sales of 45,946 Series A Cumulative Preferred Units.

Preferred Unit Equity Offerings

On March 11, 2014, we completed a public offering of 7,000,000 7.625% Series B Cumulative Preferred Units at a price of $25.00 per unit. Offers were made pursuant to a prospectus supplement to the Shelf Registration Statement. We received proceeds of approximately $169.3 million from this offering, after deducting underwriting discounts of $5.5 million and offering costs of

$0.2 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

On September 15, 2014, we completed a public offering of 4,000,000 7.75% Series C Cumulative Preferred Units at a price of $25.00 per unit. Offers were made pursuant to a prospectus supplement to the Shelf Registration Statement. We received proceeds of approximately $96.9 million from this offering, after deducting underwriting discounts of $3.2 million and offering costs of $0.2 million. On September 23, 2014, we received additional proceeds of approximately $7.3 million from the sale of an additional 300,000 Series C Cumulative Preferred Units that were purchased pursuant to the underwriters' over-allotment option. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

Subsidiary Guarantors

We and VNR Finance Corp., our wholly-owned finance subsidiary, may co-issue securities pursuant to our effective shelf registration statement. VNR has no independent assets or operations. Debt securities that we may offer may be guaranteed by our subsidiaries. We contemplate that if we offer guaranteed debt securities, the guarantees will be full and unconditional and joint and several, and any subsidiaries of Vanguard that do not guarantee the securities will be minor.

Debt and Credit Facilities

Reserve-Based Credit Facility

The Company's Third Amended and Restated Credit Agreement (the "Credit Agreement") provides a maximum credit facility of $3.5 billion and an initial borrowing base of $2.0 billion (the "Reserve-Based Credit Facility") with a maturity date of April 16, 2018. On December 31, 2014, there were $1.36 billion of outstanding borrowings and $634.5 million of borrowing capacity under the Reserve-Based Credit Facility, after reflecting a $5.5 million reduction in availability for letters of credit (discussed below).

On October 30, 2014, we entered into the Seventh Amendment to the Credit Agreement, which provided for, among others, (a) the increase in the maximum amount of debt under capital leases from $2.0 million to $35.0 million and (b) the increase in the aggregate amount of restricted payments that can be used to repurchase the Company's units over the term of the Credit Agreement from $10.0 million to $50.0 million.

Interest rates under the Reserve-Based Credit Facility are based on Euro-Dollars (LIBOR) or ABR (Prime) indications, plus a margin. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. The applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Percentage	<25%		>25% <50%		>50% <75%		>75% <90%		>90%	
Eurodollar Loans Margin	1.50	%	1.75	%	2.00	%	2.25	%	2.50	%
ABR Loans Margin	0.50	%	0.75	%	1.00	%	1.25	%	1.50	%
Commitment Fee Rate	0.50	%	0.50	%	0.375	%	0.375	%	0.375	%
Letter of Credit Fee	0.50	%	0.75	%	1.00	%	1.25	%	1.50	%

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and

NGLs reserves. Based on projected market conditions and lower commodity prices, it is likely that banks will lower their internal projections of oil, natural gas and NGLs prices, and we expect that we will be subject to a decrease in our borrowing base availability in the future. We also currently expect that we will not be in compliance with our debt to Adjusted EBITDA covenant in certain future periods. We have been in discussions with certain banks in our Reserve-Based Credit Facility regarding amending our debt to Adjusted EBITDA covenant during our next scheduled borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted Adjusted EBITDA due to the lower commodity price environment. Our next borrowing base redetermination is scheduled for April 2015. Our current borrowing base is $2.0 billion.

As of February 27, 2014, we have $634.5 million available to be borrowed under our Reserve-Based Credit Facility, after reflecting a $5.5 million reduction in availability for letters of credit (as discussed below).

Borrowings under the Reserve-Based Credit Facility are available for development and acquisition of oil and natural gas properties, working capital and general limited liability company purposes. Our obligations under the Reserve-Based Credit Facility are secured by substantially all of our assets.

At our election, interest is determined by reference to:

- the London interbank offered rate, or LIBOR, plus an applicable margin between 1.50% and 2.50% per annum; or

- a domestic bank rate plus an applicable margin between 0.50% and 1.50% per annum.

As of December 31, 2014, we have elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

The Reserve-Based Credit Facility contains various covenants that limit our ability to:

- incur indebtedness;

- grant certain liens;

- make certain loans, acquisitions, capital expenditures and investments;

- merge or consolidate; or

- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

The Reserve-Based Credit Facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC Topic 815, which includes the current portion of derivative contracts; and

- consolidated debt to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures of not more than 4.0 to 1.0.

We have the ability to borrow under the Reserve-Based Credit Facility to pay distributions to unitholders as long as there has not been a default or event of default.

We believe that we are in compliance with the terms of our Reserve-Based Credit Facility at December 31, 2014. If an event of default exists under the reserve-based credit agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Each of the following will be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;

- a representation or warranty is proven to be incorrect when made;

- failure to perform or otherwise comply with the covenants in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;

- default by us on the payment of any other indebtedness in excess of $5.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;

- bankruptcy or insolvency events involving us or our subsidiaries;

- the entry of, and failure to pay, one or more adverse judgments in excess of 2% of the existing borrowing base (to the extent not covered by independent third-party insurance provided by insurers of the highest claims paying rating or financial strength as to which the insurer does not dispute coverage and is not subject to insolvency proceeding) or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;

- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year; and

- a change of control, which includes (1) an acquisition of ownership, directly or indirectly, beneficially or of record, by any person or group (within the meaning of the Exchange Act and the rules and regulations of the SEC) of equity interests representing more than 25% of the aggregate ordinary voting power represented by our issued and outstanding equity interests, or (2) the replacement of a majority of our directors by persons not approved by our board of directors.

Letters of Credit

At December 31, 2014, we had unused irrevocable standby letters of credit of approximately $5.5 million. The letters are being maintained as security for performance on long-term transportation contracts. Borrowing availability for the letters of credit is provided under our Reserve-Based Credit Facility. The fair value of these letters of credit approximates contract values based on the nature of the fee arrangements with the issuing banks.

Senior Notes

We have $550.0 million outstanding in aggregate principal amount of 7.875% senior notes due 2020 (the "Senior Notes"). The Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured basis, by our Subsidiary Guarantors, subject to the same guaranty release conditions. Under the indenture governing the Senior Notes (the "Indenture"), all of our existing subsidiaries (other than VNRF), all of which are 100% owned, and certain of our future subsidiaries (the "Subsidiary Guarantors") have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to release under certain of the following circumstances: (i) upon the sale or other disposition of all or substantially all of the subsidiary's properties or assets, (ii) upon the sale or other disposition of our equity interests in the subsidiary, (iii) upon designation of the subsidiary as an unrestricted subsidiary in accordance with the terms of the Indenture, (iv) upon legal defeasance or covenant defeasance or the discharge of the Indenture, (v) upon the liquidation or dissolution of the subsidiary; (vi) upon the subsidiary ceasing to guarantee any other of our indebtedness and to be an obligor under any of our credit facilities, or (vii) upon such subsidiary dissolving or ceasing to exist after consolidating with, merging into or transferring all of its properties or assets to us.

The Indenture also contains covenants that will limit our ability to (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) make distributions on, purchase or redeem our common units or purchase or redeem subordinated indebtedness; (iv) make investments; (v) restrict dividends, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of our properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; (viii) enter into transactions with affiliates; or (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. If the Senior Notes achieve an investment grade rating from each of Standard & Poor's Rating Services and Moody's Investors Services, Inc. and no default under the Indenture exists, many of the foregoing covenants will terminate. At December 31, 2014, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, $245.0 million of members' equity is available for distributions to unitholders, while the remainder is restricted.

Interest on the Senior Notes is payable on April 1 and October 1 of each year. We may redeem some or all of the Senior Notes at any time on or after April 1, 2016 at redemption prices of 103.93750% of the aggregate principal amount of the Senior Notes as of April 1, 2016, declining to 100% on April 1, 2018 and thereafter. We may also redeem some or all of the Senior Notes at any time prior to April 1, 2016 at a redemption price equal to 100% of the aggregate principal amount of the Senior Notes thereof, plus a "make-whole" premium. In addition, before April 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price equal to 107.875% of the aggregate principal amount of the Senior Notes thereof, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of the Senior Notes remain outstanding immediately after any such redemption and the redemption occurs within 180 days of such equity offering. If we sell certain of our assets or experience certain changes of control, we may be required to repurchase all or a portion of the Senior Notes at a price equal to 100% and 101% of the aggregate principal amount of the Senior Notes, respectively.

Lease Financing Obligations

On October 24, 2014, as part of our Piceance Acquisition, we entered into an assignment and assumption agreement with Bank of America Leasing & Capital, LLC as the lead bank, whereby we acquired compressors and the related facilities, and assumed the related financing obligations (the "Lease Financing Obligations"). Certain rights, title, interest and obligations under the Lease Financing Obligations have been assigned to several lenders and are covered by separate assignment agreements, which expire on August 10, 2020 and July 10, 2021. We have the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligations also contain an early buyout option where the Company may purchase the equipment for $16.0 million on February 10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 4.16%.

Off-Balance Sheet Arrangements

We have no guarantees or off-balance-sheet debt to third parties, and we maintain no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Contingencies

The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. As of December 31, 2014, there were no material loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of December 31, 2014 is provided in the following table.

	Payments Due by Year (in thousands)						
	2015	2016	2017	2018	2019	Thereafter	Total
Management base salaries	$1,404	$—	$—	$—	$—	$—	$1,404
Asset retirement obligations (1)	2,386	12,440	4,490	5,750	2,963	121,033	149,062
Derivative liabilities (2)	45,600	20,099	2,585	—	—	—	68,284
Reserve-Based Credit Facility (3)	—	—	—	1,360,000	—	—	1,360,000
Senior Notes and related interest	54,141	43,313	43,313	43,313	43,313	564,438	791,831
Operating leases	1,191	1,071	1,089	1,337	1,342	216	6,246
Development commitments (4)	45,850	—	—	—	—	—	45,850
Firm transportation and processing agreements (5)	17,454	13,986	11,840	11,261	9,661	410	64,612
Lease Financing Obligations (6)	4,318	4,501	4,692	4,891	5,098	5,486	28,986
Total	$172,344	$95,410	$68,009	$1,426,552	$62,377	$691,583	$2,516,275

(1) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and decommissioning of our Elk Basin and Fairway gas plants. Please read Note 6 of the Notes to the Consolidated

Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our asset retirement obligations.

(2) Represents liabilities for commodity and interest rate derivative contracts, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read “Item 7A. Quantitative and Qualitative Disclosures about Market Risk” and Note 4 of the Notes to the Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our commodity and interest rate derivative contracts.

(3) This table does not include interest to be paid on the principal balances shown as the interest rates on our financing arrangements are variable. Please read Note 3 of the Notes to the Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our long-term debt.

(4) Represents authorized purchases for work in process.

(5) Represents transportation demand charges. Please read Note 8 of the Notes to the Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

(6) The Lease Financing Obligations are calculated based on the aggregate present value of minimum future lease payments.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, natural gas and NGLs prices and interest rates. The disclosures are not meant to be precise indicators of exposure, but rather indicators of potential exposure. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. Conditions sometimes arise where actual production is less than estimated, which has, and could result in overhedged volumes.

Commodity Price Risk

Our primary market risk exposure is in the prices we receive for our production. Realized pricing for our natural gas and oil production is primarily driven by spot market prices applicable to our natural gas production and the prevailing price for crude oil. Our natural gas production is primarily sold under market sensitive contracts which are typically priced at published natural gas index prices for the producing area due to the natural gas quality and the proximity to major consuming markets. Our natural gas indexes include the Houston Ship Channel, West Texas ("Waha Index"), El Paso Natural Gas Company (Permian Basin), Transwestern (Permian), Colorado Interstate Gas Co. (Rocky Mountains Index), Northwest Pipeline Corp. (Rocky Mountains Index), Transcontinental Gas Pipe Line Corp: Zone 4 and Enable Gas: East index. As for oil production, realized pricing is primarily driven by WTI, the Light Louisiana Sweet Crude, Flint Hills Bow River and Net Energy Canadian Daily Index for Western Canadian Select prices and calendar NYMEX pricing. The NGLs price exposure is centered on the Oil Price Information Service postings as well as market-negotiated ethane spot prices.

Pricing for oil, natural gas and NGLs production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control. In addition, the potential exists that if commodity prices decline to a certain level, the borrowing base for our Reserve-Based Credit Facility can be decreased at the borrowing base redetermination date to an amount lower than the amount of debt currently outstanding and, because it would be uneconomical, production could decline to levels below our hedged volumes. Furthermore, the risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase.

We routinely enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that mitigate the volatility of future prices received as follows:

- Fixed-price swaps - where we will receive a fixed-price for our production and pay a variable market price to the contract counterparty.
- Basis swap contracts - which guarantee a price differential between the NYMEX prices and our physical pricing points. We receive a payment from the counterparty or make a payment to the counterparty for the difference between the settled price differential and amounts stated under the terms of the contract.
- Collars - where we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor (long put) on a notional quantity.
- Three-way collar contracts - which combine a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher price thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle for market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.
- Swaption agreements - where we provide options to counterparties to extend swap contracts into subsequent years.

- Call options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a call option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Put spread options - created when we purchase a put and sell a put simultaneously.
- Put options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a put option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Range bonus accumulators - a structure that allows us to receive a cash payment when the crude oil or natural gas settlement price remains within a predefined range on each expiry date. Depending on the terms of the contract, if the settlement price is below the floor or above the ceiling on any expiry date, we may have to sell at that level.

In deciding which type of derivative instrument to use, our management considers the relative benefit of each type against any cost that would be incurred, prevailing commodity market conditions and management’s view on future commodity pricing.

The amount of oil and natural gas production which is hedged is determined by applying a percentage to the expected amount of production in our most current reserve report in a given year. Substantially all of our natural gas hedges are at regional sales points in our operating regions, which mitigate the risk of basis differential to the Henry Hub index. Typically, management intends to hedge 75% to 85% of projected oil and natural gas production up to a four year period. These activities are intended to support our realized commodity prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. Currently, we are unable to hedge oil differentials in certain operating areas which exposes our cash flow to increased volatility in these areas. We have also entered into fixed-price swaps derivative contracts to cover a portion of our NGLs production to reduce exposure to fluctuations in NGLs prices. However, a liquid, readily available and commercially viable market for hedging NGLs has not developed in the same way that exists for crude oil and natural gas. The current direct NGLs hedging market is constrained in terms of price, volume, tenor and number of counterparties, which limits our ability to hedge our NGLs production effectively or at all. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Management will consider liquidating a derivative contract, if they believe that they can take advantage of an unusual market condition allowing them to realize a current gain and then have the ability to enter into a new derivative contract in the future at or above the commodity price of the contract that was liquidated.

At December 31, 2014, the fair value of commodity derivative contracts was a net asset of approximately $225.4 million, of which $141.8 million settles during the next twelve months. A 10% increase in the oil and natural gas index price above the December 31, 2014 price would result in a net decrease in the fair value of all of our commodity derivative contracts of approximately $51.6 million; conversely, a 10% decrease in the oil and natural gas index price would result in a net increase of approximately $63.1 million. This sensitivity analysis measures the current value of the commodity derivative contracts using forward price curves and volatility surfaces under a proprietary system and then increases or decreases, as applicable, the forward price curve to determine the fair value of the commodity derivative contracts under the assumed oil and natural gas price indexes.

The following table summarizes commodity derivative contracts in place at December 31, 2014:

	Year 2015	Year 2016	Year 2017
Gas Positions:			
Fixed-Price Swaps:			
Notional Volume (MMBtu)	66,795,000	55,083,000	27,677,000
Fixed Price ($/MMBtu)	$4.40	$4.47	$4.32
Three-Way Collars:			
Notional Volume (MMBtu)	17,337,500	12,810,000	12,775,000
Floor Price ($/MMBtu)	$3.99	$3.95	$3.97
Ceiling Price ($/MMBtu)	$4.67	$4.58	$4.61
Put Sold ($/MMBtu)	$3.38	$3.38	$3.40
Total Gas Positions:			
Notional Volume (MMBtu)	84,132,500	67,893,000	40,452,000
Floor Price ($/MMBtu)	$4.32	$4.37	$4.21

	Year 2015	Year 2016	Year 2017
Oil Positions:			
Fixed-Price Swaps:			
Notional Volume (Bbls)	692,000	146,400	73,000
Fixed Price ($/Bbl)	$91.18	$89.98	$86.60
Three-Way Collars:			
Notional Volume (Bbls)	1,984,055	1,061,400	—
Floor Price ($/Bbl)	$92.05	$90.00	$—

Ceiling Price ($/Bbl)	$95.74	$96.18	$—
Put Sold ($/Bbl)	$74.41	$73.62	$—
Total Oil Positions:			
Notional Volume (Bbls)	2,676,055	1,207,800	73,000
Floor Price ($/Bbl)	$91.83	$90.00	$86.60

	Year 2015
NGLs Positions:	
Fixed-Price Swaps:	
Mont Belvieu Propane	
Notional Volume (Bbls)	164,250
Fixed Price ($/Bbl)	$43.21
Mont Belvieu N. Butane	
Notional Volume (Bbls)	36,500
Fixed Price ($/Bbl)	$52.08
Mont Belvieu Isobutane	
Notional Volume (Bbls)	45,625
Fixed Price ($/Bbl)	$53.00
Total NGLs Positions:	
Notional Volume (Bbls)	246,375
Fixed Price ($/Bbl)	$46.34

As of December 31, 2014, the Company had sold the following put option contracts:

	Year 2015	Year 2016	Year 2017
Gas Positions:			
Notional Volume (MMbtu)	9,125,000	1,830,000	1,825,000
Put Sold ($/MMbtu)	$3.50	$3.50	$3.50
Oil Positions:			
Notional Volume (Bbls)	692,000	146,400	73,000
Put Sold ($/Bbl)	$72.36	$75.00	$75.00

As of December 31, 2014, the Company had the following open range bonus accumulators contracts:

	Year 2015	Year 2016
Gas Positions:		
Notional Volume (MMBtu)	1,460,000	—
Bonus ($/MMBtu)	$0.20	$—
Digital call sold ($/MMBtu)	$4.75	$—
Put Sold ($/MMBtu)	$3.25	$—
Oil Positions:		
Notional Volume (Bbls)	182,500	183,000
Bonus ($/Bbl)	$4.00	$4.00
Digital call sold ($/Bbl)	$100.00	$100.00
Put Sold ($/Bbl)	$75.00	$75.00

As of December 31, 2014, the Company had the following open basis swap contracts:

	Year 2015	Year 2016	Year 2017
Gas Positions:			
Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential			
Notional Volume (MMBtu)	29,200,000	18,300,000	10,950,000
Weighted-basis differential ($/MMBtu)	$(0.28)	$(0.24)	$(0.22)

	Year 2015
Oil Positions:	
WTI Midland and WTI Cushing Basis Differential	
Notional Volume (Bbls)	511,000
Weighted-basis differential ($/Bbl)	$(1.68)
West Texas Sour and WTI Cushing Basis Differential	
Notional Volume (Bbls)	146,000
Weighted-basis differential ($/Bbl)	$(2.33)

As of December 31, 2014, the Company sold calls as follows:

	Year 2015	Year 2016
Oil Positions:		
Notional Volume (Bbls)	252,945	622,200
Weighted Average Fixed Price ($/Bbl)	$97.89	$125.00

Recently, the Company has taken steps to restructure its hedge portfolio to limit further downside and volatility due to the current commodity price environment. Specifically, the Company has converted a significant portion of its three-way collars in 2015 to fixed-price swaps or lowered the pricing on existing short puts. We have implemented a hedging program for approximately 77% and 45% of our anticipated crude oil production in 2015 and 2016, respectively, with 88% in the form of fixed-price swaps in 2015. Approximately 82% and 67% of our natural gas production in 2015 and 2016, respectively, is hedged with 98% in the form of fixed-price swaps in 2015. NGLs production is under fixed-price swaps for approximately 9% of anticipated production in 2015.

	Year 2015	Year 2016	Year 2017
Gas Production Hedged:			
% Anticipated Production Hedged	82 %	67 %	40 %
Weighted Average Price ($/MMBtu)	$ 4.32	$ 4.37	$ 4.18
Oil Production Hedged:			
% Anticipated Production Hedged	77 %	45 %	—
Weighted Average Price ($/Bbl)	$ 76.12	$ 83.02	$ —
NGLs Production Hedged:			
% Anticipated Production Hedged	9 %	—	—
Weighted Average Price ($/Bbl)	$ 46.34	$ —	$ —

Interest Rate Risks

At December 31, 2014, we had debt outstanding of $1.9 billion. The amount outstanding under our Reserve-Based Credit Facility at December 31, 2014 of $1.36 billion is subject to interest at floating rates based on LIBOR. If the debt remains the same, a 10% increase in LIBOR would result in an estimated $0.2 million increase in annual interest expense after consideration of the interest rate swaps discussed below. We also had $550.0 million aggregate principal amount of 7.875% Senior Notes and $29.0 million aggregate principal amount of Lease Financing Obligations with an implied interest of 4.16%.

We enter into interest rate swaps, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates. The Company records changes in the fair value of its interest rate derivatives in current earnings under net gains (losses) on interest rate derivative contracts.

The following summarizes information concerning our positions in open interest rate swaps at December 31, 2014 (in thousands):

	Year 2015 (1) (2)	Year 2016
Weighted Average Notional Amount	$344,959	$169,399
Weighted Average Fixed LIBOR Rate	1.27 %	1.49 %

(1) The counterparty has the option to extend the termination date of a contract for a notional amount of $30.0 million at 2.25% to August 5, 2018.

(2) The counterparty has the option to require Vanguard to pay a fixed LIBOR rate of 0.91% for a notional amount of $50.0 million from December 10, 2015 to December 10, 2017.

Counterparty Risk

At December 31, 2014, based upon all of our open derivative contracts shown above and their respective mark-to-market values, the Company had the following current and long-term derivative assets and liabilities shown by counterparty with their S&P financial strength rating in parentheses (in thousands):

	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities	Total Amount Due From/(Owed To) Counterparty at December 31, 2014
Bank of America (A)	$10,441	$6,779	$(702)	$(211)	$16,307
Barclays (A)	7,798	3,618	—	—	11,416
BMO (A+)	6,223	3,999	—		10,222
CIBC (A+)	1,757	2	—	—	1,759
Citibank (A)	10,015	1,351	—	—	11,366
Comerica (A)	1,606	854	—	—	2,460
Commonwealth Bank of Australia (AA-)	894	469		—	1,363
Credit Agricole (A)	—	—	(402)	(255)	(657)
Credit Suisse (A)	1,829	1,460	—	—	3,289
Deutsche Bank (A)	709	688	—	—	1,397
Fifth Third Bank (A-)	5,579	731	—	—	6,310
ING Financial Markets (A)	1,654	1,138			2,792
JP Morgan (A)	34,676	32,873	—	—	67,549
Morgan Stanley (A-)	7,078	4,002	—	—	11,080
Natixis (A)	13,265	2,835	—	—	16,100
RBC (AA-)	6,717	5,831	(9)	—	12,539
Scotia Capital (A+)	18,205	9,812	(711)	(583)	26,723
Shell (AA-)	—	—	(294)	—	(294)
Sun Trust (A-)	894	469		—	1,363
Wells Fargo (AA-)	12,774	6,672	(1,465)	(331)	17,650

Total	$142,114	$83,583	$(3,583)	$(1,380)	$220,734

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with our counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each financial transaction between the counterparty and us separately, the master netting agreement enables the counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (i) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (ii) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out. Under the master netting agreement, the maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the net fair value of financial instruments, was approximately $221.7 million at December 31, 2014.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Below is an index to the items contained in this "Item 8. Financial Statements and Supplementary Data."

All schedules are omitted as the required information is not applicable or the information is presented in the Consolidated Financial Statements and related notes.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Members
Vanguard Natural Resources, LLC
Houston, Texas

We have audited the accompanying consolidated balance sheets of Vanguard Natural Resources, LLC as of December 31, 2014 and 2013 and the related consolidated statements of operations, members' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Vanguard Natural Resources, LLC at December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Vanguard Natural Resources LLC's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
March 2, 2015

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Operations
For the Years Ended December 31,
(in thousands, except per unit data)

	2014	2013	2012
Revenues:			
Oil sales	$268,685	$268,922	$233,153
Natural gas sales	285,439	124,513	47,270
Natural gas liquids sales	70,489	49,813	29,933
Net gains on commodity derivative contracts	163,452	11,256	36,846
Total revenues	788,065	454,504	347,202
Costs and expenses:			
Production:			
Lease operating expenses	132,515	105,502	74,366
Production and other taxes	61,874	40,430	29,369
Depreciation, depletion, amortization and accretion	226,937	167,535	104,542
Impairment of oil and natural gas properties	234,434	—	247,722
Selling, general and administrative expenses	30,839	25,942	22,466
Total costs and expenses	686,599	339,409	478,465
Income (loss) from operations	101,466	115,095	(131,263)
Other income (expense):			
Interest expense	(69,765)	(61,148)	(41,891)
Net losses on interest rate derivative contracts	(1,933)	(96)	(6,992)
Net gain on acquisitions of oil and natural gas properties	34,523	5,591	11,111
Other	54	69	220
Total other expense	(37,121)	(55,584)	(37,552)
Net income (loss)	64,345	59,511	(168,815)
Less: Distributions to Preferred unitholders	(18,197)	(2,634)	—
Net income (loss) available to Common and Class B unitholders	$46,148	$56,877	$(168,815)
Net income (loss) per Common and Class B unit:			
Basic	$0.56	$0.78	$(3.11)
Diluted	$0.55	$0.77	$(3.11)
Weighted average units outstanding:			
Common units – basic	81,611	72,644	53,777
Common units – diluted	82,039	72,992	53,777
Class B units – basic & diluted	420	420	420

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Balance Sheets
As of December 31,
(in thousands, except unit data)

	2014	2013
Assets		
Current assets		
Cash and cash equivalents	$—	$11,818
Trade accounts receivable, net	140,017	70,109
Derivative assets	142,114	21,314
Other currents assets	4,102	2,916
Total current assets	286,233	106,157
Oil and natural gas properties, at cost	4,140,527	2,523,671
Accumulated depletion, amortization and impairment	(1,164,721)	(713,154)
Oil and natural gas properties evaluated, net – full cost method	2,975,806	1,810,517
Other assets		
Goodwill	420,955	420,955
Derivative assets	83,583	60,474
Other assets	27,015	91,538
Total assets	$3,793,592	$2,489,641
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$15,118	$9,824
Affiliates	823	249
Accrued liabilities:		
Lease operating	19,822	12,882
Developmental capital	24,706	10,543
Interest	11,517	11,989
Production and other taxes	29,981	16,251
Derivative liabilities	3,583	10,992
Oil and natural gas revenue payable	40,117	23,245
Distributions payable	18,640	16,499
Other	14,297	12,929
Total current liabilities	178,604	125,403
Long-term debt	1,932,816	1,007,879
Derivative liabilities	1,380	4,085
Asset retirement obligations	146,676	82,208
Other long-term liabilities	—	1,731
Total liabilities	2,259,476	1,221,306
Commitments and contingencies (Note 8)		
Members' equity		
Cumulative Preferred units, 13,881,873 and 2,535,927 units issued and outstanding at December 31, 2014 and 2013	335,444	61,021
Members' capital, 83,451,746 and 78,337,259 common units issued and outstanding at December 31, 2014 and 2013, respectively	1,191,057	1,199,699
Class B units, 420,000 issued and outstanding at December 31, 2014 and 2013	7,615	7,615

Total members’ equity	1,534,116	1,268,335
Total liabilities and members’ equity	$3,793,592	$2,489,641

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Members' Equity
For the Years Ended December 31, 2014, 2013 and 2012
(in thousands)

	Cumulative Preferred Units	Common Units	Class B Units	Total Members' Equity
Balance, January 1, 2012	$—	$836,306	$7,615	$843,921
Issuance of Common units, net of offering costs of $1,109	—	321,900	—	321,900
Distributions to Common and Class B unitholders (see Note 9)	—	(152,190)	—	(152,190)
Common units received in exchange for Appalachian Basin properties	—	(52,480)	—	(52,480)
Unit-based compensation	—	4,178	—	4,178
Options exercised	—	950	—	950
Net loss	—	(168,815)	—	(168,815)
Balance at December 31, 2012	—	789,849	7,615	797,464
Issuance of Common units for the acquisition of oil and natural gas properties	—	29,992	—	29,992
Issuance of Cumulative Preferred units, net of offering costs of $402	61,021	—	—	61,021
Issuance of Common units, net of offering costs of $415	—	498,360	—	498,360
Distributions to Preferred unitholders (see Note 9)	—	(2,634)	—	(2,634)
Distributions to Common and Class B unitholders (see Note 9)	—	(181,926)	—	(181,926)
Unit-based compensation	—	6,547	—	6,547
Net income	—	59,511	—	59,511
Balance at December 31, 2013	61,021	1,199,699	7,615	1,268,335
Issuance of Cumulative Preferred units, net of offering costs of $371	274,423	—	—	274,423
Issuance of Common units, net of offering costs of $88	—	147,814	—	147,814
Repurchase of units under the common unit buyback program	—	(2,498)	—	(2,498)
Distributions to Preferred unitholders (see Note 9)	—	(18,197)	—	(18,197)
Distributions to Common and Class B unitholders (see Note 9)	—	(207,883)	—	(207,883)
Unit-based compensation	—	7,777	—	7,777
Net income	—	64,345	—	64,345
Balance at December 31, 2014	$335,444	$1,191,057	$7,615	$1,534,116

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Cash Flows
For the Years Ended December 31,
(in thousands)

	2014	2013	2012
Operating activities			
Net income (loss)	$64,345	$59,511	$(168,815)

Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	226,937	167,535	104,542
Impairment of oil and natural gas properties	234,434	—	247,722
Amortization of deferred financing costs	3,516	3,715	2,925
Amortization of debt discount	269	248	172
Compensation related items	10,706	5,931	5,421
Net gains on commodity and interest rate derivative contracts	(161,519)	(11,160)	(29,854)
Net cash settlements received on matured commodity derivative contracts	10,187	30,905	39,102
Net cash settlements paid on matured interest rate derivative contracts	(4,035)	(3,888)	(2,515)
Net gain on acquisitions of oil and natural gas properties	(34,523)	(5,591)	(11,111)
Changes in operating assets and liabilities:			
Trade accounts receivable	(69,908)	(22,065)	3,778
Payables to affiliates	574	217	(1,647)
Premiums paid on commodity derivative contracts	—	(204)	(8,158)
Other current assets	(1,669)	(603)	(318)
Accounts payable and oil and natural gas revenue payable	22,166	16,426	8,604
Accrued expenses and other current liabilities	29,377	18,855	14,375
Other assets	8,895	1,133	267
Net cash provided by operating activities	339,752	260,965	204,490
Investing activities			
Additions to property and equipment	(1,356)	(1,975)	(721)
Additions to oil and natural gas properties	(142,015)	(56,661)	(50,405)
Acquisitions of oil and natural gas properties and derivative contracts	(1,302,568)	(272,057)	(783,355)
Proceeds from the sale of oil and natural gas properties	4,973	—	5,522
Deposits and prepayments of oil and natural gas properties	(5,236)	(67,284)	(10,285)
Net cash used in investing activities	(1,446,202)	(397,977)	(839,244)
Financing activities			
Proceeds from long-term debt	1,388,000	589,500	1,477,459
Repayment of debt	(488,000)	(829,500)	(1,001,000)
Proceeds from preferred unit offerings, net	274,423	61,021	—
Proceeds from common unit offerings, net	147,814	498,360	321,900
Repurchase of units under the common unit buyback program	(2,498)	—	—
Distributions to Preferred unitholders	(17,290)	(2,426)	—
Distributions to Common and Class B members	(206,649)	(177,555)	(140,271)
Financing fees	(1,168)	(2,133)	(15,572)
Exercised options granted to officers	—	—	950
Net cash provided by financing activities	1,094,632	137,267	643,466
Net increase (decrease) in cash and cash equivalents	(11,818)	255	8,712
Cash and cash equivalents, beginning of year	11,818	11,563	2,851
Cash and cash equivalents, end of year	$—	$11,818	$11,563
Supplemental cash flow information:			
Cash paid for interest	$66,434	$57,067	$27,625
Non-cash financing and investing activities:			
Asset retirement obligations	$56,947	$22,692	$26,365
Assets acquired under financing obligations	$31,502	$—	$—
Common units issued for the acquisition of oil and gas properties	$—	$29,992	$—
Common units received in exchange for the Appalachian Basin properties	$—	$—	$52,480

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Notes to Consolidated Financial Statements
December 31, 2014

Description of the Business:

Vanguard Natural Resources, LLC is a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increase our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, as of December 31, 2014, we own properties and oil and natural gas reserves primarily located in nine operating basins:

- the Green River Basin in Wyoming;
- the Piceance Basin in Colorado;
- the Permian Basin in West Texas and New Mexico;
- the Gulf Coast Basin in Texas, Louisiana and Mississippi;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Williston Basin in North Dakota and Montana;
- the Wind River Basin in Wyoming; and
- the Powder River Basin in Wyoming.

References in this report to “us,” “we,” “our,” the “Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC (“VNG”), VNR Holdings, LLC (“VNRH”), Vanguard Permian, LLC (“Vanguard Permian”), Vanguard Operating, LLC (“VO”), VNR Finance Corp. (“VNRF”), Encore Energy Partners Operating LLC (“OLLC”) and Encore Clear Fork Pipeline LLC. References in this report to “our operating subsidiary” or “VNG” are to Vanguard Natural Gas, LLC.

1. Summary of Significant Accounting Policies

(a) Basis of Presentation and Principles of Consolidation:

Our consolidated financial statements are prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) and include the accounts of all subsidiaries after the elimination of all significant intercompany accounts and transactions. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income or members’ equity.

(b) New Pronouncement Issued But Not Yet Adopted:

In May 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU No. 2014-09"), which amends the FASB ASC by adding new FASB ASC Topic 606, Revenue from Contracts with Customers, and superseding the revenue recognition requirements in FASB ASC 605, Revenue Recognition, and in most industry-specific topics. The standard provides new guidance concerning recognition and measurement of revenue and requires additional disclosures about the nature, timing and uncertainty of revenue and cash flows arising from contracts with customers. ASU No. 2014-09 is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are evaluating the impact of the pending adoption of ASU No. 2014-09 on our financial position and results of operations and have not yet determined the method by which it will adopt the standard in 2017.

(c) Cash Equivalents:

The Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

(d) Accounts Receivable and Allowance for Doubtful Accounts:

Accounts receivable are customer obligations due under normal trade terms and are presented on the Consolidated Balance Sheets net of allowances for doubtful accounts. We establish provisions for losses on accounts receivable if we determine that it is likely that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

(e) Inventory:

Materials, supplies and commodity inventories are valued at the lower of cost or market. The cost is determined using the first-in, first-out method. Inventories are included in other current assets in the accompanying Consolidated Balance Sheets.

(f) Oil and Natural Gas Properties:

The full cost method of accounting is used to account for oil and natural gas properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil, natural gas and natural gas liquids ("NGLs") reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and subject to ceiling test limitations as discussed below.

Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurs on a quarterly basis. Specifically, costs are transferred to the amortizable base when properties are determined to have proved reserves. In addition, we transfer unproved property costs to the amortizable base when unproved properties are evaluated as being impaired and as exploratory wells are determined to be unsuccessful. Additionally, the amortizable base includes estimated future development costs, dismantlement, restoration and abandonment costs net of estimated salvage values.

Capitalized costs are limited to a ceiling based on the present value of estimated future net cash flows from proved reserves, computed using the 12-month unweighted average of first-day-of-the-month commodity prices (the "12-month average price"), discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is less than the total capitalized costs, we are required to write down capitalized costs to the ceiling. We perform this ceiling test calculation each quarter. Any required write-downs are included in the Consolidated Statements of Operations as an impairment charge.

We recorded a non-cash ceiling test impairment of oil and natural gas properties for the year ended December 31, 2014 of $234.4 million as a result of a decline in realized oil and natural gas prices at the measurement date, December 31, 2014. Such impairment was recognized during the fourth quarter of 2014. The most significant factor affecting the 2014 impairment related to the properties that we acquired in the Piceance Acquisition. The fair value of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) was higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. However, the impairment calculations did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. The fourth quarter 2014 impairment was calculated based on prices of $4.36 per MMBtu for natural gas and $94.87 per barrel of crude oil. No ceiling test impairment was required during 2013.

During the year ended December 31, 2012, we recorded a non-cash ceiling test impairment of oil and natural gas properties of $247.7 million as a result of a decline in natural gas prices at the measurement dates, September 30, 2012 and December 31, 2012. Such impairment was recognized during the third and fourth quarters of 2012. The most significant factor affecting the 2012 impairment related to the properties that we acquired in the Arkoma Basin Acquisition and Rockies Acquisition (discussed below). The fair values of the properties acquired (determined using forward oil and natural gas price curves at the acquisitions dates) were higher than the discounted estimated future cash flows computed using the 12-month average prices at the impairment test measurement dates. We were able to lock in higher future selling prices for a portion of the estimated natural gas production for the Arkoma Basin Acquisition and the Rockies Acquisition by using commodity derivative contracts. However, our impairment calculations do not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow us to consider the expected cash flows from derivatives designated as cash flow hedges. The 2012 third quarter impairment was calculated based on prices of $2.77 per MMBtu for natural gas and $95.26 per barrel of crude oil while the 2012 fourth quarter impairment was calculated based on prices of $2.76 per MMBtu for natural gas and $94.67 per barrel of crude oil.

When we sell or convey interests in oil and natural gas properties, we reduce oil and natural gas reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or loss on sales of oil and natural gas properties unless those sales would significantly alter the relationship between capitalized costs and proved reserves. Sales proceeds on insignificant sales are treated as an adjustment to the cost of the properties.

(g) Goodwill and Other Intangible Assets:

We account for goodwill and other intangible assets under the provisions of the Accounting Standards Codification (ASC) Topic 350, "Intangibles-Goodwill and Other." Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is not amortized, but is tested for impairment annually on October 1 or whenever indicators of impairment exist using a two-step process. The goodwill test is performed at the reporting unit level, which represents our oil and natural gas operations in the United States. The first step involves a comparison of the estimated fair value of a reporting unit to its net book value, which is its carrying amount, including goodwill. In performing the first step, we determine the fair value of the reporting unit using the market approach. Determining fair value requires the exercise of significant judgment, including judgments about market prices and other relevant information generated by market transactions involving identical or comparable assets, liabilities, or a group of assets and liabilities, such as a business. If the estimated fair value of the reporting unit exceeds its net book value, goodwill of the reporting unit is not impaired and the second step of the impairment test is not necessary. If the net book value of the reporting unit exceeds its fair value, the second step of the goodwill impairment test will be performed to measure the amount of impairment loss, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit's goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. In other words, the estimated fair value of the reporting unit is allocated to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination and the fair value of the reporting unit was the purchase price paid. If the carrying amount of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess.

We performed our annual impairment tests during 2014, 2013 and 2012 and our analyses concluded that there was no impairment of goodwill as of these dates. However, due to the current decline in the prices of oil and natural gas as well as deteriorating market conditions, we performed an interim impairment test at December 31, 2014. Based on our estimates, the fair value of our reporting unit exceeded its carrying value by 8% at December 31, 2014 and therefore the second step of the impairment test was not necessary. We believe this difference between the fair value and the net book value is appropriate (in the context of assessing whether a goodwill impairment may exist) when a market-based control premium is taken into account and in light of the recent volatility in the equity markets.

While no goodwill impairment was recognized at December 31, 2014, any further significant decline in the prices of oil and natural gas as well as any continued declines in the quoted market price of the Company's units could change our estimate of the fair value of the reporting unit and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. We evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

We are a party to a contract allowing us to purchase a certain amount of natural gas at a below market price for use as field fuel. As of December 31, 2014, the net carrying value of this contract was $8.3 million. The carrying value is shown as Other assets on the accompanying Consolidated Balance Sheets and is amortized on a straight-line basis over the estimated life of the field. The estimated aggregate amortization expense for each of the next five fiscal years is $0.2 million per year.

(h) Asset Retirement Obligations:

We record a liability for asset retirement obligations at fair value in the period in which the liability is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the asset’s useful life. Our recognized asset retirement obligation exclusively relates to the plugging and abandonment of oil and natural gas wells and decommissioning of our Elk Basin and Fairway gas plants. Management periodically reviews the estimates of the timing of well abandonments as well as the estimated plugging and abandonment costs, which are discounted at the credit adjusted risk free rate. These retirement costs are recorded as a long-term liability on the Consolidated Balance Sheets with an offsetting increase in oil and natural gas properties. An ongoing accretion expense is recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion, amortization and accretion expense in the Consolidated Statements of Operations.

(i) Revenue Recognition and Gas Imbalances:

Sales of oil, natural gas and NGLs are recognized when oil, natural gas and NGLs have been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. We sell oil, natural gas and NGLs on a monthly basis. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil, natural gas or NGLs, and prevailing supply and demand conditions, so that the price of the oil, natural gas and NGLs fluctuates to remain competitive with other available oil, natural gas and NGLs supplies. To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as "Trade accounts receivable, net" in the accompanying Consolidated Balance Sheets.

The Company has elected the entitlements method to account for gas production imbalances. Gas imbalances occur when we sell more or less than our entitled ownership percentage of total gas production. Any amount received in excess of our share is treated as a liability. If we receive less than our entitled share the underproduction is recorded as a receivable. The amounts of imbalances were not material at December 31, 2014 and 2013.

(j) Concentrations of Credit Risk:

Financial instruments that potentially subject us to concentrations of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative contracts. We control our exposure to credit risk associated with these instruments by (i) placing our assets and other financial interests with credit-worthy financial institutions, (ii) maintaining policies over credit extension that include the evaluation of customers' financial condition and monitoring payment history, although we do not have collateral requirements and (iii) netting derivative assets and liabilities for counterparties where we have a legal right of offset.

At December 31, 2014 and 2013, the cash and cash equivalents were concentrated in one financial institution. We periodically assess the financial condition of this institution and believe that any possible credit risk is minimal.

The following purchasers accounted for 10% or more of the Company's oil, natural gas and NGLs sales for the years ended December 31:

	2014	2013	2012
Anadarko Petroleum Corporation	19%	1%	—%
Marathon Oil Company	12%	14%	21%
Plains Marketing L.P.	7%	10%	15%

Our customers are in the energy industry and they may be similarly affected by changes in economic or other conditions.

(k) Use of Estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGLs reserves and related cash flow estimates used in impairment tests of oil and natural gas properties, the fair value of assets and liabilities acquired in business combinations, goodwill, derivative contracts, asset retirement obligations, accrued oil, natural gas and NGLs revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

(l) Price and Interest Rate Risk Management Activities:

We have entered into derivative contracts primarily with counterparties that are also lenders under our financing arrangements to hedge price risk associated with a portion of our oil, natural gas and NGLs production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in overhedged volumes. Our natural gas production is primarily sold under market sensitive contracts which are typically priced at a differential to the NYMEX or the published natural gas index prices for the producing area due to the natural gas quality and the proximity to major consuming markets. As for oil production, realized pricing is primarily driven by the West Texas Intermediate ("WTI"), Light Louisiana Sweet Crude, Wyoming Imperial and Flint Hills Bow River prices. NGLs pricing is based on the Oil Price Information Service postings as well as market-negotiated ethane spot prices. During 2014, our derivative transactions included the following:

- Fixed-price swaps - where we receive a fixed-price for our production and pay a variable market price to the contract counterparty.
- Basis swap contracts - which guarantee a price differential between the NYMEX prices and our physical pricing points. We receive a payment from the counterparty or make a payment to the counterparty for the difference between the settled price differential and amounts stated under the terms of the contract.
- Collars - where we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor (long put) on a notional quantity.
- Three-way collar contracts - which combine a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher price thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle for market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.
- Swaption agreements - where we provide options to counterparties to extend swap contracts into subsequent years.
- Call options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a call option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Put spread options - created when we purchase a put and sell a put simultaneously.
- Put options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position or a lower liability position. In general, selling a put option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Range bonus accumulators - a structure that allows us to receive a cash payment when the crude oil or natural gas settlement price remains within a predefined range on each expiry date. Depending on the terms of the contract, if the settlement price is below the floor or above the ceiling on any expiry date, we may have to sell at that level.

We also enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under our financing arrangements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

Under ASC Topic 815, "Derivatives and Hedging," all derivative instruments are recorded on the Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair values are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the change in the fair value of the derivative is deferred in accumulated other comprehensive income (loss) in the equity section of the Consolidated Balance Sheets to the extent the hedge is effective. Gains and losses on cash flow hedges included in accumulated other comprehensive income (loss) are reclassified to gains (losses) on commodity cash flow hedges or gains (losses) on interest rate derivative contracts in the period that the related production is delivered or the contract settles. Gains or losses on derivative contracts that do not qualify for hedge accounting treatment are recorded in net gains (losses) on commodity derivative contracts or net gains (losses) on interest rate derivative contracts in the Consolidated Statements of Operations.

We have elected not to designate our current portfolio of derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in net gains (losses) on commodity derivative contracts or net gains (losses) on interest rate derivative contracts in the accompanying Consolidated Statements of Operations.

Any premiums paid on derivative contracts and the fair value of derivative contracts acquired in connection with our acquisitions are capitalized as part of the derivative assets or derivative liabilities, as appropriate, at the time the premiums are paid or the contracts are assumed. Premium payments are reflected in cash flows from operating activities in our Consolidated

Statements of Cash Flows. When the consideration for an acquisition is cash, the fair value of any derivative contracts acquired in the acquisition is reflected in cash flows from investing activities. Over time, as the derivative contracts settle, the differences between the cash received and the premiums paid or fair value of contracts acquired are recognized in net gains or losses on commodity or interest rate derivate contracts, and the cash received is reflected in cash flows from operating activities in our Consolidated Statements of Cash Flows.

(m) Income Taxes:

The Company is treated as a partnership for federal and state income tax purposes. As such, it is not a taxable entity and does not directly pay federal and state income tax. Its taxable income or loss, which may vary substantially from the net income or net loss reported in the Consolidated Statements of Operations, is included in the federal and state income tax returns of each unitholder. Accordingly, no recognition has been given to federal and state income taxes for the operations of the Company. The aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Company does not have access to information about each unitholders' tax attributes in the Company. However, the tax basis of our net assets exceeded the net book basis by $187.0 million at December 31, 2014 while the book basis of our net assets exceeded the net tax basis by $168.5 million at December 31, 2013.

Legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax, including otherwise non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the Revised Texas Franchise Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. The Company recorded a current tax liability of $0.2 million and $0.3 million as of December 31, 2014 and 2013, respectively, and a deferred tax asset of $0.3 million and deferred tax liability of $0.4 million as of December 31, 2014 and 2013, respectively. A benefit of $0.6 million and tax provisions of $0.6 million and $0.2 million are included in our Consolidated Statements of Operations for the years ended December 31, 2014, 2013, and 2012, respectively, as a component of Selling, general and administrative expenses.

2. Acquisitions and Divestiture

Our acquisitions are accounted for under the acquisition method of accounting in accordance with ASC Topic 805, "Business Combinations" ("ASC Topic 805"). An acquisition may result in the recognition of a gain or goodwill based on the measurement of the fair value of the assets acquired at the acquisition date as compared to the fair value of consideration transferred, adjusted for purchase price adjustments. Any such gain or any loss resulting from the impairment of goodwill is recognized in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations. The initial accounting for acquisitions may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition dates. The results of operations of the properties acquired in our acquisitions have been included in the consolidated financial statements since the closing dates of the acquisitions. All our acquisitions were funded with borrowings under our Reserve-Based Credit Facility (defined in Note 3), except for certain acquisitions, in which the Company issued shares or exchanged assets as described below.

2014 Acquisitions

Pinedale Acquisition

On January 31, 2014, we completed the acquisition of natural gas and oil properties in the Pinedale and Jonah fields of Southwestern Wyoming for approximately $555.6 million in cash with an effective date of October 1, 2013. We refer to this acquisition as the “Pinedale Acquisition.” In accordance with ASC Topic 805, this acquisition resulted in a gain of $32.1 million, as reflected in the table below, primarily due to the increase in natural gas prices between the date the purchase and sale agreement was entered into and the closing date.

Fair value of assets and liabilities acquired	(in thousands)
Oil and natural gas properties	$ 600,123
Inventory	244
Asset retirement obligations	(12,404)
Imbalance liabilities	(171)
Other	(125)
Total fair value of assets and liabilities acquired	587,667
Fair value of consideration transferred	555,553
Gain on acquisition	$ 32,114

Piceance Acquisition

On September 30, 2014, we completed the acquisition of natural gas, oil and NGLs assets in the Piceance Basin in Colorado for approximately $502.1 million in cash. We refer to this acquisition as the "Piceance Acquisition." Through this acquisition, we acquired additional interests in the same properties previously acquired in the Rockies Acquisition as defined below. The purchase price is subject to additional customary post-closing adjustments to be determined based on an effective date of July 1, 2014. In accordance with ASC Topic 805, this acquisition resulted in goodwill of $0.4 million, as reflected in the table below, which was immediately impaired and recorded as a loss in current period earnings. The loss resulted primarily from the changes in natural gas prices between the date the purchase and sale agreement was entered into and the closing date, which were used to value the reserves acquired.

Fair value of assets and liabilities acquired	(in thousands)
Oil and natural gas properties	$ 521,401
Asset retirement obligations	(19,452)
Imbalance and suspense liabilities	(236)
Total fair value of assets and liabilities acquired	501,713
Fair value of consideration transferred	502,140
Loss on acquisition	$ (427)

Other Acquisitions

On May 1, 2014, we completed an asset exchange transaction with Marathon Oil Company in which we acquired natural gas and NGLs properties in the Wamsutter natural gas field in Wyoming in exchange for 75% of our working interests in the Gooseberry Field properties in Wyoming. The total consideration for this transaction was the mutual exchange and assignment of interests in the properties and net cash consideration of $6.8 million paid to Marathon Oil Company. The cash consideration was funded with borrowings under our existing Reserve-Based Credit Facility and is subject to customary final post-closing adjustments to be determined based on an effective date of January 1, 2014.

On August 29, 2014, we completed the acquisition of certain natural gas, oil and NGLs properties located in North Louisiana and East Texas for an adjusted purchase price of $269.9 million, subject to additional customary post-closing adjustments to be determined based on an effective date of June 1, 2014.

During the year ended December 31, 2014, we completed other smaller acquisitions of certain natural gas, oil and NGLs properties located in the Permian Basin and Powder River Basin in Wyoming for an aggregate purchase price of $17.7 million.

2013 Acquisitions

On April 1, 2013, we completed the acquisition of certain natural gas, oil and NGLs properties located in the Permian Basin in southeast New Mexico and West Texas for an adjusted purchase price of $266.2 million. This acquisition had an effective date of January 1, 2013.

On June 28, 2013, we completed the acquisition of certain natural gas, oil and NGLs properties located in the Permian Basin in Texas and the San Juan and DJ-Basin in Colorado with an effective date of July 1, 2013 for an adjusted purchase price of $29.9 million. The consideration for this acquisition was paid in common equity by issuing 1,075,000 VNR common units, at an agreed price of $27.65 per common unit, valued for financial reporting purposes at the closing price of $27.90 at the closing date of the acquisition.

We also completed other acquisitions during 2013 including the acquisition of additional working interests in previously acquired properties for an aggregate adjusted purchase price of $2.5 million.

The following presents the values assigned to the net assets acquired in our 2013 acquisitions:

Fair value of assets and liabilities acquired:	(in thousands)
Oil and natural gas properties	$317,573
Inventory	899
Asset retirement obligations	(11,381)
Oil and natural gas revenue payable and imbalance liabilities	(2,843)
Total fair value of assets and liabilities acquired	304,248
Fair value of consideration transferred	298,657
Gain on acquisition	$5,591

2012 Acquisitions

On June 1, 2012, we entered into a purchase and sale agreement with Antero Resources LLC for the acquisition of natural gas and liquids properties in the Woodford Shale in Oklahoma and Fayetteville Shale in Arkansas of the Arkoma Basin. We refer to this acquisition as the “Arkoma Basin Acquisition”. We completed this acquisition on June 29, 2012 with an effective date of April 1, 2012 for an adjusted purchase price of $428.5 million. Upon closing this acquisition, we assumed natural gas swaps valued at $109.5 million on the closing date, which were restructured in July 2012 to cover the estimated natural gas production from existing producing wells in the acquired properties over the next five years from the date the natural gas swaps were restructured. In accordance with ASC Topic 805, this acquisition resulted in a gain of $14.1 million, as reflected in the table below, primarily due to the changes in the value of derivative assets between the date the purchase and sale agreement was entered into and the closing date, which were driven by corresponding changes in natural gas prices.

Fair value of assets and liabilities acquired:	(in thousands)
Oil and natural gas properties	$344,747
Derivative assets	109,495
Asset retirement obligations	(8,922)
Oil and natural gas revenue payable and imbalance liabilities	(2,653)
Total fair value of assets and liabilities acquired	442,667
Fair value of consideration transferred	428,541
Gain on acquisition	$14,126

On October 31, 2012, we entered into a purchase and sale agreement with Bill Barrett Corporation for the acquisition of natural gas and liquids properties in the Piceance Basin in Colorado and Powder River and Wind River Basins in Wyoming. We refer to this acquisition as the “Rockies Acquisition.” This acquisition had an effective date of October 1, 2012. With respect to the Piceance Basin properties, we had an escalating working interest wherein our working interest began at 18% and increased to 21% on January 1, 2014, and was scheduled to increase to 24% on January 1, 2015 and 26% on January 1, 2016. This structure was designed to maintain cash flow from the acquisition without the need for any capital spending until 2016. We completed this acquisition on December 31, 2012 for an adjusted purchase price of $324.7 million. As noted above, we acquired all of Bill Barrett Corporation’s remaining interest in these properties in the Piceance Acquisition. This acquisition resulted in goodwill of $8.8 million, as reflected in the table below, which was immediately impaired and recorded as a loss in current period earnings. The loss resulted primarily from the changes in oil and natural gas prices between the date the purchase and sale agreement was entered into and the closing date, which were used to value the reserves acquired.

Fair value of assets and liabilities acquired:	(in thousands)
Oil and natural gas properties	$330,707
Other assets	929
Asset retirement obligations	(15,763)
Oil and natural gas revenue payable and imbalance liabilities	(41)
Total fair value of assets and liabilities acquired	315,832
Fair value of consideration transferred	324,650
Loss on acquisition	$(8,818)

During 2012, we completed other smaller acquisitions of oil and natural gas properties located in our various operating regions, primarily in Wyoming and North Dakota for adjusted purchase prices aggregating to $24.8 million. One of these properties was initially included as part of a larger acquisition that we did not complete as a result of a third party exercising their preferential rights to acquire a portion of the properties. The fair value of the properties acquired in this acquisition exceeded the purchase price allocated to them in the initial agreement and thus, resulted in a gain of $6.0 million.

2012 Divestiture

We previously owned properties in the Appalachian Basin, which is primarily in southeast Kentucky and northeast Tennessee (the “Appalachian Basin”). On February 21, 2012, we and our 100% owned operating subsidiary entered into a Unit Exchange Agreement with Majeed S. Nami Personal Endowment Trust and Majeed S. Nami Irrevocable Trust (collectively, the “Nami Parties”) to transfer our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC, which entities operated all of our ownership interests in oil and natural gas properties in the Appalachian Basin, in exchange for 1.9 million of our common units valued at the closing price of our common units of $27.62 per unit at March 30, 2012, or $52.5 million, with an effective date of January 1, 2012 (the “Unit Exchange”). The Nami Parties are controlled by or affiliated with Majeed S. Nami who was a founding unitholder when we completed the IPO. We completed this transaction on March 30, 2012 for non-cash consideration of $52.5 million, which was offset by post-closing adjustments of $1.4 million.

Pro Forma Operating Results (Unaudited)

In accordance with ASC Topic 805, presented below are unaudited pro forma results for the years ended December 31, 2014, 2013 and 2012 which reflect the effect on our consolidated results of operations as if (i) all our acquisitions in 2014 had occurred on January 1, 2013, (ii) all our acquisitions in 2013 had occurred on January 1, 2012 and (iii) all our acquisitions in 2012 had occurred on January 1, 2011. The unaudited pro forma results also reflect the impact of the Unit Exchange, including the elimination of the results of operations from the properties we previously owned in the Appalachian Basin and the receipt of the 1.9 million common units received as consideration for the exchange, as if it had occurred on January 1, 2011.

The pro forma results reflect the results of combining our Consolidated Statements of Operations with the revenues and direct operating expenses of the oil and gas properties acquired adjusted for (i) assumption of asset retirement obligations and accretion expense for the properties acquired, (ii) depletion expense applied to the adjusted basis of the properties acquired using the acquisition method of accounting, (iii) interest expense on additional borrowings necessary to finance the acquisitions, (iv) interest expense on the Senior Notes (defined in Note 3), including the amortization of discount and (v) the impact of the common units issued in the acquisition of properties completed on June 28, 2013. We used a portion of the net proceeds from our Senior Notes offering to repay all indebtedness outstanding under our second lien term loan, then outstanding, and applied the balance of the net proceeds to outstanding borrowings under our Reserve-Based Credit Facility. The repayment therefore resulted in an increase in the amount available for borrowing under our Reserve-Based Credit Facility. The pro forma results reflect the fact that the increase in borrowing capacity provided us available funding for the Arkoma Basin Acquisition. The net gain (loss) on acquisition of oil and natural gas properties were excluded from the pro forma results. The pro forma information is based upon these assumptions, and is not necessarily indicative of future results of operations:

	Year Ended December 31,		
	2014	2013	2012
	(in thousands, except per unit amounts)		(Pro forma)
Total revenues	$944,246	$841,576	$557,802
Net income (loss) attributable to Common and Class B unitholders	$254,345	$161,329	$(174,187)
Net income (loss) attributable to Common and Class B unitholders, per unit:			
Basic	$3.10	$2.19	$(3.18)
Diluted	$3.07	$2.17	$(3.18)

The amount of revenues and excess of revenues over direct operating expenses that were eliminated to reflect the impact of the Unit Exchange in the pro forma results presented above are as follows (in thousands):

	Year Ended December 31, 2012
Revenues	$3,267
Net loss	$(400)

Post-Acquisition Operating Results

The results of operations of the properties acquired, as described above, have been included in our consolidated financial statements from the closing dates of the acquisitions forward. The table below presents the amounts of revenues and excess of revenues over direct operating expenses included in our 2014, 2013 and 2012 Consolidated Statements of Operations for our acquisitions. Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes.

	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Pinedale Acquisition			
Revenues	$139,908	$—	$—
Excess of revenues over direct operating expenses	$107,934	$—	$—
Piceance Acquisition			
Revenues	$22,642	$—	$—
Excess of revenues over direct operating expenses	$15,234	$—	$—
Arkoma Basin Acquisition			
Revenues	$62,450	$55,468	$24,673
Excess of revenues over direct operating expenses	$48,847	$45,090	$19,971
Rockies Acquisition			
Revenues	$67,707	$63,652	$220
Excess of revenues over direct operating expenses	$40,505	$41,583	$164
All other acquisitions			
Revenues	$79,009	$37,096	$1,535
Excess of revenues over direct operating expenses	$51,956	$24,912	$992

3. Long-Term Debt

Our financing arrangements consisted of the following:

Description	Interest Rate	Maturity Date	Amount Outstanding December 31, 2014	2013
			(in thousands)	
Senior Secured Reserve-Based Credit Facility	Variable (1)	April 16, 2018	$1,360,000	$460,000
Senior Notes	7.875% (2)	April 1, 2020	550,000	550,000
Lease Financing Obligations	4.16% (3)	August 10, 2020 (4)	28,986	—
			$1,938,986	$1,010,000
Less:				
Unamortized discount on Senior Notes			(1,852)	(2,121)
Current portion			(4,318)	—
Total long-term debt			$1,932,816	$1,007,879

(1) Variable interest rate was 2.17% and 1.92% at December 31, 2014 and 2013, respectively.
(2) Effective interest rate is 8.0%.
(3) Effective interest rate is 6.48%.
(4) The Lease Financing Obligations expire on August 10, 2020 except for certain obligations which expire on July 10, 2021.

Senior Secured Reserve-Based Credit Facility

The Company's Third Amended and Restated Credit Agreement (the "Credit Agreement") provides a maximum credit facility of $3.5 billion and an initial borrowing base of $2.0 billion (the "Reserve-Based Credit Facility"). On December 31, 2014, there were $1.36 billion of outstanding borrowings and $634.5 million of borrowing capacity under the Reserve-Based Credit Facility, after reflecting a $5.5 million reduction in availability for letters of credit (discussed below).

On October 30, 2014, we entered into the Seventh Amendment to the Credit Agreement, which provided for, among others, (a) the increase in the maximum amount of debt under capital leases from $2.0 million to $35.0 million and (b) the increase in the aggregate amount of restricted payments that can be used to repurchase the Company's units over the term of the Credit Agreement from $10.0 million to $50.0 million.

Interest rates under the Reserve-Based Credit Facility are based on Euro-Dollars (LIBOR) or ABR (Prime) indications, plus a margin. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. At December 31, 2014, the applicable margin and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	>25% <50%	>50% <75%	>75% <90%	>90%
Eurodollar Loans Margin	1.50%	1.75%	2.00%	2.25%	2.50%
ABR Loans Margin	0.50%	0.75%	1.00%	1.25%	1.50%
Commitment Fee Rate	0.50%	0.50%	0.375%	0.375%	0.375%
Letter of Credit Fee	0.50%	0.75%	1.00%	1.25%	1.50%

Our Reserve-Based Credit Facility contains a number of customary covenants that require us to maintain certain financial ratios. Specifically, as of the end of each fiscal quarter, we may not permit the following: (a) our current ratio to be less than 1.0 to 1.0 and (b) our total leverage ratio to be more than 4.0 to 1.0. In addition, we are subject to various other covenants including, but not limited to, those limiting our ability to incur indebtedness, enter into commodity and interest rate derivatives, grant certain liens, make certain loans, acquisitions, capital expenditures and investments, merge or consolidate, or engage in certain asset dispositions, including a sale of all or substantially all of our assets.

At December 31, 2014, we were in compliance with all of our debt covenants. Based on projected market conditions and lower commodity prices, we currently expect that we will not be in compliance with our total leverage ratio covenant in certain future periods. We have been in discussions with certain banks in our Reserve-Based Credit Facility regarding amending our leverage ratio covenant during our next scheduled borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted Adjusted EBITDA due to the lower commodity price environment. Our next borrowing base redetermination is scheduled for April 2015 and we expect our borrowing base to be reduced. Absent the success of amending our leverage ratio, a resultant breach of the covenants under our Reserve-Based Credit Facility would cause a default under the reserve-based credit agreement and the lenders would be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. This, in turn, would cause a default under the senior notes due in 2020 and permit the holders of those notes to accelerate their maturity.

Letters of Credit

At December 31, 2014, we had unused irrevocable standby letters of credit of approximately $5.5 million. The letters are being maintained as security for performance on long-term transportation contracts. Borrowing availability for the letters of credit is provided under our Reserve-Based Credit Facility. The fair value of these letters of credit approximates contract values based on the nature of the fee arrangements with the issuing banks.

Senior Notes

We have $550.0 million outstanding in aggregate principal amount of 7.875% senior notes due in 2020 (the "Senior Notes"). The issuers of the Senior Notes are VNR and our 100% owned finance subsidiary, VNRF. VNR has no independent assets or operations. Under the indenture governing the Senior Notes (the "Indenture"), all of our existing subsidiaries (other than VNRF), all of which are 100% owned, and certain of our future subsidiaries (the "Subsidiary Guarantors") have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to release under certain of the following circumstances: (i) upon the sale or other disposition of all or substantially all of the subsidiary's properties or assets, (ii) upon the sale or other disposition of our equity interests in the subsidiary, (iii) upon designation of the subsidiary as an unrestricted subsidiary in accordance with the terms of the Indenture, (iv) upon legal defeasance or covenant defeasance or the discharge of the Indenture, (v) upon the liquidation or dissolution of the subsidiary; (vi) upon the subsidiary ceasing to guarantee any other of our indebtedness and to be an obligor under any of our credit facilities, or (vii) upon such subsidiary dissolving or ceasing to exist after consolidating with, merging into or transferring all of its properties or assets to us.

The Indenture also contains covenants that will limit our ability to (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) make distributions on, purchase or redeem our common units or purchase or redeem subordinated indebtedness; (iv) make investments; (v) restrict dividends, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of our properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; (viii) enter into transactions with affiliates; or (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. If the Senior Notes achieve an investment grade rating from each of Standard & Poor's Rating Services and Moody's Investors Services, Inc. and no default under the Indenture exists, many of the foregoing covenants will terminate. At December 31, 2014, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, $245.0 million of members' equity is available for distributions to unitholders, while the remainder is restricted.

Interest on the Senior Notes is payable on April 1 and October 1 of each year. We may redeem some or all of the Senior Notes at any time on or after April 1, 2016 at redemption prices of 103.93750% of the aggregate principal amount of the Senior Notes as of April 1, 2016, declining to 100% on April 1, 2018 and thereafter. We may also redeem some or all of the Senior Notes at any time prior to April 1, 2016 at a redemption price equal to 100% of the aggregate principal amount of the Senior Notes thereof, plus a "make-whole" premium. In addition, before April 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price equal to 107.875% of the aggregate principal amount of the Senior Notes thereof, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of the Senior Notes remain outstanding immediately after any such redemption and the redemption occurs within 180 days of such equity offering. If we sell certain of our assets or experience certain changes of control, we may be required to repurchase all or a portion of the Senior Notes at a price equal to 100% and 101% of the aggregate principal amount of the Senior Notes, respectively.

Lease Financing Obligations

On October 24, 2014, in connection with our Piceance Acquisition, we entered into an assignment and assumption agreement, whereby we acquired compressors and the related facilities, and assumed the related financing obligations (the "Lease Financing Obligations"). Certain rights, title, interest and obligations under the Lease Financing Obligations have been assigned to several lenders and are covered by separate assignment agreements, which expire on August 10, 2020 and July 10, 2021. We have the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligations also contain an early buyout option where the Company may purchase the equipment for $16.0 million on February

10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 4.16%.

4. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts primarily with counterparties that are also lenders under our Reserve-Based Credit Facility to hedge price risk associated with a portion of our oil, natural gas and NGLs production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in overhedged volumes. Pricing for these derivative contracts are based on certain market indexes and prices at our primary sales points.

We also enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under our Reserve-Based Credit Facility, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

At December 31, 2014, the Company had open commodity derivative contracts covering our anticipated future production as follows:

Fixed-Price Swaps

	Gas		Oil		NGLs	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	Weighted Average WTI Price	Bbls	Weighted Average Fixed Price
January 1, 2015 – December 31, 2015	66,795,000	$4.40	692,000	$91.18	246,375	$46.34
January 1, 2016 – December 31, 2016	55,083,000	$4.47	146,400	$89.98	—	$—
January 1, 2017 – December 31, 2017	27,677,000	$4.32	73,000	$86.60	—	$—

Call Options Sold

	Oil	
Contract Period	Bbls	Weighted Average Fixed Price
January 1, 2015 – December 31, 2015	252,945	$97.89
January 1, 2016 – December 31, 2016	622,200	$125.00

Basis Swaps

	Gas		
Contract Period	MMBtu	Weighted Avg. Basis Differential ($/MMBtu)	Pricing Index
January 1, 2015 – December 31, 2015	29,200,000	$(0.28)	Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential

January 1, 2016 – December 31, 2016	18,300,000	$(0.24)	Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential
January 1, 2017 – December 31, 2017	10,950,000	$(0.22)	Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential

Contract Period	Oil Bbls	Weighted Avg. Basis Differential ($/Bbl)	Pricing Index
January 1, 2015 – December 31, 2015	511,000	$(1.68)	WTI Midland and WTI Cushing Basis Differential
January 1, 2015 – December 31, 2015	146,000	$(2.33)	West Texas Sour and WTI Cushing Basis Differential

Three-Way Collars

Contract Period	Gas MMbtu	Floor	Ceiling	Put Sold
January 1, 2015 – December 31, 2015	17,337,500	$3.99	$4.67	$3.38
January 1, 2016 – December 31, 2016	12,810,000	$3.95	$4.58	$3.38
January 1, 2017 – December 31, 2017	12,775,000	$3.97	$4.61	$3.40

Contract Period	Oil Bbls	Floor	Ceiling	Put Sold
January 1, 2015 – December 31, 2015	1,984,055	$92.05	$95.74	$74.41
January 1, 2016 – December 31, 2016	1,061,400	$90.00	$96.18	$73.62

Put Options Sold

Contract Period	Gas MMbtu	Put Sold ($/MMbtu)	Oil Bbls	Put Sold ($/Bbl)
January 1, 2015 – December 31, 2015	9,125,000	$3.50	692,000	$72.36
January 1, 2016 – December 31, 2016	1,830,000	3.50	146,400	$75.00
January 1, 2017 – December 31, 2017	1,825,000	3.50	73,000	$75.00

Range Bonus Accumulators

Contract Period	Gas MMBtu	Bonus	Range Ceiling	Range Floor
January 1, 2015 – December 31, 2015	1,460,000	$0.20	$4.75	$3.25

Contract Period	Oil Bbls	Bonus	Range Ceiling	Range Floor
January 1, 2015 – December 31, 2015	182,500	$4.00	$100.00	$75.00
January 1, 2016 – December 31, 2016	183,000	$4.00	$100.00	$75.00

In January 2015, we restructured our hedge portfolio to limit further downside and volatility due to the current commodity price environment. See Note 12. Subsequent Events for further discussion.

Interest Rate Swaps

We may from time to time enter into interest rate swap agreements based on LIBOR to minimize the effect of fluctuations in interest rates. These interest rate swap agreements require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates. If LIBOR is lower than the fixed rate in the contract, we are required to pay the counterparty the difference, and conversely, the counterparty is required to pay us if LIBOR is higher than the fixed rate in the contract. We do not designate interest rate swap agreements as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings.

At December 31, 2014, the Company had open interest rate derivative contracts as follows (in thousands):

	Notional Amount	Fixed LIBOR Rates
Period:		
January 1, 2015 to December 10, 2016	$20,000	2.17 %
January 1, 2015 to October 31, 2016	$40,000	1.65 %
January 1, 2015 to August 5, 2015 (1)	$30,000	2.25 %
January 1, 2015 to August 6, 2016	$25,000	1.80 %
January 1, 2015 to October 31, 2016	$20,000	1.78 %
January 1, 2015 to September 23, 2016	$75,000	1.15 %
January 1, 2015 to March 7, 2016	$75,000	1.08 %
January 1, 2015 to September 7, 2016	$25,000	1.25 %
January 1, 2015 to December 10, 2015 (2)	$50,000	0.21 %
Total	$360,000	

(1) The counterparty has the option to extend the termination date of this contract at 2.25% to August 5, 2018.
(2) The counterparty has the option to require Vanguard to pay a fixed rate of 0.91% from December 10, 2015 to December 10, 2017.

Balance Sheet Presentation

Our commodity derivatives and interest rate swap derivatives are presented on a net basis in “derivative assets” and “derivative liabilities” on the Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments and the impact of offsetting the derivative assets and liabilities on our Consolidated Balance Sheets for the periods indicated (in thousands):

	December 31, 2014		
Offsetting Derivative Assets:	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Commodity price derivative contracts	$289,018	$(63,321)	$225,697
Total derivative instruments	$289,018	$(63,321)	$225,697
Offsetting Derivative Liabilities:	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Commodity price derivative contracts	$(63,615)	$63,321	$(294)

Interest rate derivative contracts	(4,669)	—	(4,669)
Total derivative instruments	$(68,284)	$63,321	$(4,963)

	December 31, 2013		
Offsetting Derivative Assets:	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Commodity price derivative contracts	$107,307	$(25,617)	$81,690
Interest rate derivative contracts	98	—	98
Total derivative instruments	$107,405	$(25,617)	$81,788

Offsetting Derivative Liabilities:	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Commodity price derivative contracts	$(33,825)	$25,617	$(8,208)
Interest rate derivative contracts	(6,869)	—	(6,869)
Total derivative instruments	$(40,694)	$25,617	$(15,077)

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. Our counterparties are participants in our Reserve-Based Credit Facility (see Note 3 for further discussion), which is secured by our oil and natural gas properties; therefore, we are not required to post any collateral. The maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $289.0 million at December 31, 2014. In accordance with our standard practice, our commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated as of December 31, 2014. We minimize the credit risk in derivative instruments by: (i) entering into derivative instruments primarily with counterparties that are also lenders in our Reserve-Based Credit Facility and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis.

The change in fair value of our commodity and interest rate derivatives for the years ended December 31, 2014, 2013 and 2012 is as follows:

	2014	2013	2012
	(in thousands)		
Derivative asset (liability) at January 1, net	$66,711	$82,568	$(29,889)
Purchases			
Fair value of derivatives acquired through business combinations	(1,344)	—	109,495
Premiums and fees paid or deferred for derivative contracts during the period	—	—	9,695
Net gains on commodity and interest rate derivative contracts	161,519	11,160	29,854
Settlements			
Net cash settlements received on matured commodity derivative contracts	(10,187)	(30,905)	(39,102)
Net cash settlements paid on matured interest rate derivative contracts	4,035	3,888	2,515
Derivative asset at December 31, net	$220,734	$66,711	$82,568

5. Fair Value Measurements

We estimate the fair values of financial and non-financial assets and liabilities under ASC Topic 820 "Fair Value Measurements and Disclosures" ("ASC Topic 820"). ASC Topic 820 provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based compensation, are not included in the scope of ASC Topic 820. Primarily, ASC Topic 820 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, and to long-lived assets written down to fair value when they are impaired. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on SEC rules. ASC Topic 820 applies to assets and liabilities carried at fair value on the Consolidated Balance Sheets, as well as to supplemental information about the fair values of financial instruments not carried at fair value.

We have applied the provisions of ASC Topic 820 to assets and liabilities measured at fair value on a recurring basis, which includes our commodity and interest rate derivatives contracts, and on a nonrecurring basis, which includes goodwill, acquisitions of oil and natural gas properties and other intangible assets and the initial measurement of asset retirement obligations. ASC Topic 820 provides a definition of fair value and a framework for measuring fair value, as well as disclosures regarding fair value measurements. The framework requires fair value measurement techniques to include all significant assumptions that would be made by willing participants in a market transaction.

ASC Topic 820 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC Topic 820 provides a hierarchy of fair value measurements, based on the inputs to the fair value estimation process. It requires disclosure of fair values classified according to the “levels” described below. The hierarchy is based on the reliability of the inputs used in estimating fair value and requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The framework for fair value measurement assumes that transparent “observable” (Level 1) inputs generally provide the most reliable evidence of fair value and should be used to measure fair value whenever available. The classification of a fair value measurement is determined based on the lowest level (with Level 3 as the lowest) of significant input to the fair value estimation process.

The standard describes three levels of inputs that may be used to measure fair value:

Level 1	Quoted prices for identical instruments in active markets.
Level 2	Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.
Level 3	Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable. Level 3 assets and liabilities generally include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation or for which there is a lack of transparency as to the inputs used.

As required by ASC Topic 820, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Financing arrangements. The carrying amounts of our bank borrowings outstanding approximate fair value because our current borrowing rates do not materially differ from market rates for similar bank borrowings. The fair value of the Lease Financing Obligations is measured using market-based parameters of comparable term secured financing instruments and therefore we estimate that the carrying value approximates its fair value. The fair value measurements for our bank borrowings and the Lease Financing Obligations represent Level 2 inputs. As of December 31, 2014, the fair value of our Senior Notes was estimated to be $485.4 million. We consider the inputs to the valuation of our

Senior Notes to be Level 1, as fair value was estimated based on prices quoted from a third-party financial institution.

Derivative instruments. As of December 31, 2014, our commodity derivative instruments consist of fixed-price swaps, basis swap contracts, three-way collars, call options sold, put options sold and range bonus accumulators. We account for our commodity derivatives and interest rate derivatives at fair value on a recurring basis. We estimate the fair values of the fixed-price swaps and basis swap contracts based on published forward commodity price curves for the underlying commodities as of the date of the estimate. We estimate the option values of the contract floors, ceilings, collars and three-way collars using an option pricing model which takes into account market volatility, market prices and contract parameters. The discount rates used in the discounted cash flow projections are based on published LIBOR rates, Eurodollar futures rates and interest swap rates. In order to estimate the fair values of our interest rate swaps, we use a yield curve based on money market rates and interest rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. We consider the fair value estimates for these derivative instruments as a Level 2 input. We estimate the values of the range bonus accumulators using an option pricing model for both Asian Range Digital options and Asian Put options that takes into account market volatility, market prices and contract parameters. Range bonus accumulators are complex in structure requiring sophisticated valuation methods and greater subjectivity. As such, range bonus accumulators valuations may include inputs and assumptions that are less observable or require greater estimation, thereby resulting in valuations with less certainty. We consider the fair value estimates for range bonus accumulators as a Level 3 input.

Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Management validates the data provided by third parties by understanding the pricing models used, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to our commodity derivatives and interest rate derivatives.

Financial assets and financial liabilities measured at fair value on a recurring basis are summarized below (in thousands):

	December 31, 2014			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair Value
	(in thousands)			
Assets:				
Commodity price derivative contracts	$—	$232,167	$(6,470)	$225,697
Total derivative instruments	$—	$232,167	$(6,470)	$225,697
Liabilities:				
Commodity price derivative contracts	$—	$(294)	$—	$(294)
Interest rate derivative contracts	—	(4,669)	—	(4,669)
Total derivative instruments	$—	$(4,963)	$—	$(4,963)

	December 31, 2013			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
	(in thousands)			
Assets:				
Commodity price derivative contracts	$—	$81,124	$566	$81,690
Interest rate derivative contracts	—	98	—	98
Total derivative instruments	$—	$81,222	$566	$81,788
Liabilities:				
Commodity price derivative contracts	$—	$(8,208)	$—	$(8,208)
Interest rate derivative contracts	—	(6,869)	—	(6,869)
Total derivative instruments	$—	$(15,077)	$—	$(15,077)

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

	2014	2013
	(in thousands)	
Unobservable inputs at January 1,	$566	$(498)
Total losses	(8,238)	(134)
Settlements	1,202	1,198
Unobservable inputs at December 31,	$(6,470)	$566
Change in fair value included in earnings related to derivatives still held as of December 31, 2014	$(6,326)	$1,126

During periods of market disruption, including periods of volatile oil and natural gas prices, there may be certain asset classes that were in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, more derivative instruments, other than the range bonus accumulators, may fall to Level 3 and thus require more subjectivity and management judgment. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition.

We apply the provisions of ASC Topic 350 “Intangibles-Goodwill and Other.” Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is assessed for impairment annually on October 1 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level, which represents our oil and natural gas operations in the United States. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. We utilize a market approach to determine the fair value of our reporting unit. Any sharp prolonged decreases in the prices of oil and natural gas as well as any continued declines in the quoted market price of the Company’s units could change our estimates of the fair value of our reporting unit and could result in an impairment charge.

Our nonfinancial assets and liabilities that are initially measured at fair value are comprised primarily of assets acquired in business combinations and asset retirement costs and obligations. These assets and liabilities are recorded at fair value when acquired/incurred but not re-measured at fair value in subsequent periods. We classify such initial measurements as Level 3 since certain significant unobservable inputs are utilized in their determination. A reconciliation of the beginning and ending balance of our asset retirement obligations is presented in Note 6, in accordance with ASC Topic 410-20 “Asset Retirement Obligations.” During the years ended December 31, 2014 and 2013, in connection with the oil and natural gas properties acquired in all of our acquisitions, as well as new wells drilled during each year, we incurred and recorded asset retirement obligations totaling $52.8 million and $11.7 million, respectively, at fair value. We also recorded a $4.1 million and an $11.0 million change in estimate as a result of revisions to the timing or the amount of our original undiscounted estimated asset retirement costs during the years ended December 31, 2014 and 2013, respectively. The fair value of additions to the asset retirement obligation liability and certain changes in the estimated fair value of the liability are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Inputs to the valuation include: (1) estimated plug and abandonment cost per well based on our experience; (2) estimated remaining life per well based on average reserve life per field; (3) our credit-adjusted risk-free interest rate ranging between 4.8% and 5.6%; and (4) the average inflation factor (2.3%). These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are the most sensitive and subject to change.

6. Asset Retirement Obligations

The asset retirement obligations as of December 31, reported on our Consolidated Balance Sheets and the changes in the asset retirement obligations for the year ended December 31, were as follows:

	2014	2013
	(in thousands)	
Asset retirement obligation at January 1,	$87,967	$63,114
Liabilities added during the current period	52,829	11,738
Accretion expense	5,889	2,789
Change in estimate	4,118	10,954
Disposition of properties	(1,291)	—
Retirements	(450)	(628)
Total asset retirement obligation at December 31,	149,062	87,967
Less: current obligations	(2,386)	(5,759)
Long-term asset retirement obligation at December 31,	$146,676	$82,208

Accretion expense for the years ended December 31, 2014, 2013 and 2012 was $5.9 million, $2.8 million and $1.3 million, respectively. Each year we review, and to the extent necessary, revise our asset retirement obligation estimates. During 2014 and 2013, we reviewed the actual abandonment costs with previous estimates and, as a result, increased our estimates of future asset retirement obligations by a net $4.1 million and $11.0 million, respectively, to reflect increased costs incurred for plugging and abandonment.

7. Related Party Transactions

We previously owned oil and natural gas properties in the Appalachian Basin. On February 21, 2012, we and our 100% owned subsidiary, VNG, entered into the Unit Exchange with the Nami Parties to transfer our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC, which entities controlled all of our ownership interests in oil and natural gas properties in the Appalachian Basin, in exchange for 1.9 million of our common units valued at the closing price of our common units of $27.62 per unit at March 30, 2012, or $52.5 million, with an effective date of January 1, 2012. The Nami Parties are controlled by or affiliated with Majeed S. Nami who was a founding unitholder when we completed the IPO. We completed this transaction on March 30, 2012 for non-cash consideration of $52.5 million which was offset by post-closing adjustments of $1.4 million.

Prior to the completion of the Unit Exchange, we relied on Vinland Energy Eastern, LLC ("Vinland") to execute our drilling program, operate our wells and gather our natural gas in the Appalachian Basin. We reimbursed Vinland $60.00 per well per month (in addition to normal third-party operating costs) for operating our current natural gas and oil properties in the Appalachian Basin under a Management Services Agreement ("MSA") which costs were reflected in our lease operating expenses. Under a Gathering and Compression Agreement ("GCA"), Vinland received a $0.55 per Mcf transportation fee on any new wells drilled after December 31, 2006 within the area of mutual interest or "AMI." In June 2010, we began discussions with Vinland regarding an amendment to the GCA to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and jointly operated on this basis, however, no formal agreement between us and Vinland was signed. Under the GCA, the transportation fee that we paid to Vinland only encompassed transporting the natural gas to third- party pipelines at which point additional transportation fees to natural gas markets applied. These transportation fees were outlined in the GCA and are reflected in our lease operating expenses. For the year ended December 31, 2012, costs incurred under the MSA and the GCA were $0.6 million and $0.4 million, respectively. As a result of the Unit Exchange, the MSA and GCA were terminated.

8. Commitments and Contingencies

Transportation Demand Charges

As of December 31, 2014, we have contracts that provide firm transportation capacity on pipeline systems. The remaining terms on these contracts range from one to five years and require us to pay transportation demand charges regardless of the amount of pipeline capacity we utilize.

The values in the table below represent gross future minimum transportation demand charges we are obligated to pay as of December 31, 2014. However, our financial statements will reflect our proportionate share of the charges based on our working interest and net revenue interest, which will vary from property to property.

	(in thousands)
2015	$17,454
2016	13,986
2017	11,840
2018	11,261
2019	9,661
Thereafter	410
Total	$64,612

Development Commitments

We have commitments to third-party operators under joint operating agreements relating to the drilling and completion of oil and natural gas wells. Total estimated costs to be spent in 2015 is approximately $45.9 million.

Legal Proceedings

We are defendants in certain legal proceedings arising in the normal course of our business. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flow.

9. Members' Equity and Net Income per Common and Class B Unit

Cumulative Preferred Units

The following table summarizes the Company's Cumulative Preferred units outstanding at December 31, 2014 and 2013:

				2014		2013	
	Earliest Redemption Date	Liquidation Preference Per Share	Distribution Rate	Units Outstanding	Carrying Value (in thousands)	Units Outstanding	Carrying Value (in thousands)
Series A	June 15, 2023	$25.00	7.875%	2,581,873	$62,200	2,535,927	$61,021
Series B	April 15, 2024	$25.00	7.625%	7,000,000	$169,265	—	$—
Series C	October 15, 2024	$25.00	7.75%	4,300,000	$103,979	—	$—
Total Cumulative Preferred Units				13,881,873	$335,444	2,535,927	$61,021

The Series A, B and C Cumulative Preferred Units (collectively the "Cumulative Preferred Units") have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by us or converted into our common units, at our option, in connection with a change of control. The Cumulative Preferred Units can be redeemed, in whole or in part, out of amounts legally available therefore, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. We may also redeem the Cumulative Preferred Units in the event of a change of control. Holders of the Cumulative Preferred Units will have no voting rights except for limited voting rights if we fail to pay dividends for eighteen or more monthly periods (whether or not consecutive) and in certain other limited circumstances or as required by law. The Cumulative Preferred Units have a liquidation preference which is equal to the redemption price described above.

See Note 11. Shelf Registration Statement for a discussion of the changes in our Cumulative Preferred units during the year ended December 31, 2014.

Common and Class B Units

The common units represent limited liability company interests. Holders of Class B units have substantially the same rights and obligations as the holders of common units.

On October 15, 2014, our Board of Directors authorized a $10.0 million dollar common unit buyback program. The program was approved for an initial three month period and authorized us to make open market purchases pursuant to the Securities and Exchange Commission guidelines of Rule 10b-18. We intend to hold the common units to fund our VNR LTIP (defined in Note 10) as directed by the Compensation Committee. As of December 31, 2014, we have repurchased a total of 134,770 units under the common unit buyback program for an aggregate cost of $2.5 million.

The following is a summary of the changes in our common units issued during the years ended December 31, 2014, 2013 and 2012 (in thousands):

	2014	2013	2012
Beginning of period	78,337	58,706	48,320
Common units received in exchange for the Appalachian Basin properties	—	—	(1,900)
Issuance of Common units for the acquisition of oil and natural gas properties	—	1,075	—
Issuance of Common units for cash	4,864	18,377	12,149
Repurchase of units under the common unit buyback program	(135)	—	—
Unit-based compensation	386	179	87

Options exercised	—	—	50
End of period	83,452	78,337	58,706

There was no change in issued and outstanding Class B units during the years ended December 31, 2014, 2013 and 2012.

Net Income (Loss) per Common and Class B Unit

Basic net income per common and Class B unit is computed in accordance with ASC Topic 260 "Earnings Per Share" ("ASC Topic 260") by dividing net income attributable to common and Class B unitholders by the weighted average number of units outstanding during the period. Diluted net income per common and Class B unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. We use the treasury stock method to determine the dilutive effect. Class B units participate in distributions; therefore, all Class B units were considered in the computation of basic net income per unit. The Cumulative Preferred Units have no participation rights and accordingly are excluded from the computation of net income per unit.

The net income (loss) attributable to common and Class B unitholders and the weighted average units for calculating basic and diluted net income per common and Class B unit were as follows (in thousands, except per unit data):

	2014	2013	2012[a]
Net income (loss) attributable to Common and Class B unitholders	$46,148	$56,877	$(168,815)
Weighted average number of Common and Class B units outstanding - basic	82,031	73,064	54,197
Effect of dilutive securities:			
Phantom units	428	348	—
Weighted average number of Common and Class B units outstanding - diluted	82,459	73,412	54,197
Net income (loss) per Common and Class B unit			
Basic	$0.56	$0.78	$(3.11)
Diluted	$0.55	$0.77	$(3.11)

(a) For the year ended December 31, 2012, 522,500 phantom units were excluded from the calculation of diluted earnings per unit due to their antidilutive effect as we were in a loss position.

Distributions Declared

The Cumulative Preferred Units rank senior to our common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up. Distributions on the Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, unless the 15th day falls on a weekend or holiday, in which case it will be paid on the next business day, when, as and if declared by our board of directors. We will pay cumulative distributions in cash on the Preferred Units on a monthly basis at a monthly rate of 7.875% per annum of the liquidation preference of $25.00 per Series A Cumulative Preferred Unit, a monthly rate of 7.625% per annum of the liquidation preference of $25.00 per Series B Cumulative Preferred Unit and a monthly rate of 7.75% per annum of the liquidation preference of $25.00 per Series C Cumulative Preferred Unit.

The following table shows the distribution amount, declared date, record date and payment date of the cash distributions we paid on each of our common and Class B units for each period presented. Future distributions are at the discretion of our board of directors and will depend on business conditions, earnings, our cash requirements and other relevant factors.

On January 22, 2015 and February 17, 2015, our board of directors declared cash distributions on the Cumulative Preferred Units and common and Class B units attributable to the month of December 2014 and January 2015, respectively. See Note 12. Subsequent Events for further discussion.

Distribution	Cash Distributions Per Unit	Declared Date	Record Date	Payment Date
2014				
Fourth Quarter				
November	$0.21	December 16, 2014	January 2, 2015	January 14, 2015
October	$0.21	November 20, 2014	December 1, 2014	December 15, 2014
Third Quarter				
September	$0.21	October 20, 2014	November 3, 2014	November 14, 2014
August	$0.21	September 19, 2014	October 1, 2014	October 15, 2014
July	$0.21	August 19, 2014	September 2, 2014	September 12, 2014
Second Quarter				
June	$0.21	July 16, 2014	August 1, 2014	August 14, 2014
May	$0.21	June 24, 2014	July 1, 2014	July 15, 2014
April	$0.21	May 20, 2014	June 2, 2014	June 13, 2014
First Quarter				
March	$0.21	April 17, 2014	May 1, 2014	May 15, 2014
February	$0.21	March 17, 2014	April 1, 2014	April 14, 2014
January	$0.2075	February 2, 2014	March 3, 2014	March 17, 2014
2013				
Fourth Quarter				
December	$0.2075	January 16, 2014	February 3, 2014	February 14, 2014
November	$0.2075	December 17, 2013	January 2, 2014	January 15, 2014
October	$0.2075	November 19, 2013	December 2, 2013	December 13, 2013
Third Quarter				
September	$0.2075	October 21, 2013	November 1, 2013	November 14, 2013
August	$0.2075	September 12, 2013	October 1, 2013	October 15, 2013
July	$0.2075	August 20, 2013	September 3, 2013	September 13, 2013
Second Quarter				
June	$0.2050	July 18, 2013	August 1, 2013	August 14, 2013
May	$0.2050	June 20, 2013	July 1, 2013	July 15, 2013
April	$0.2050	April 30, 2013	June 3, 2013	June 14, 2013
First Quarter				
March	$0.2025	April 19, 2013	May 1, 2013	May 15, 2013
February	$0.2025	March 21, 2013	April 1, 2013	April 12, 2013
January	$0.2025	February 18, 2013	March 1, 2013	March 15, 2013
2012				
Fourth Quarter				
December	$0.2025	January 25, 2013	February 4, 2013	February 14, 2013
November	$0.2025	December 19, 2012	January 2, 2013	January 14, 2013
October	$0.2025	November 16, 2012	December 3, 2012	December 14, 2012
Third Quarter				
September	$0.20	October 18, 2012	November 1, 2012	November 14, 2012
August	$0.20	September 17, 2012	October 1, 2012	October 15, 2012
July	$0.20	August 20, 2012	September 4, 2012	September 14, 2012
Second Quarter	$0.60	July 23, 2012	August 7, 2012	August 14, 2012
First Quarter	$0.5925	April 24, 2012	May 8, 2012	May 15, 2012
2011				
Fourth Quarter	$0.5875	January 18, 2012	February 7, 2012	February 14, 2012

10. Unit-Based Compensation

Long-Term Incentive Plan

The Vanguard Natural Resources, LLC Long-Term Incentive Plan (the “VNR LTIP”) was adopted by the Board of Directors of the Company to compensate employees, consultants, and nonemployee directors of the Company and its affiliates who perform services for the Company under the terms of the plan. The VNR LTIP is administered by the compensation committee of the board of directors (the “Compensation Committee”) and permits the grant of unrestricted units, restricted units, phantom units, unit options and unit appreciation rights.

Unit Options

In October 2007, two officers were granted options to purchase an aggregate of 175,000 units under the VNR LTIP with an exercise price equal to the initial public offering price of $19.00, which vested immediately upon being granted and had a fair value of $0.1 million on the date of grant. These options were to expire on October 29, 2012. The grant date fair value for these option awards was calculated in accordance with ASC Topic 718, “Compensation-Stock Compensation” (“ASC Topic 718”) by calculating the Black-Scholes value of each option, using a volatility rate of 12.18%, an expected dividend yield of 8.95% and a discount rate of 5.12%, and multiplying the Black-Scholes value by the number of options awarded. In determining a volatility rate of 12.18%, we, due to a lack of historical data regarding our common units, used the historical volatility of the Citigroup MLP Index over the 365 day period prior to the date of grant. In September 2012, one of the officers exercised the option to purchase 50,000 of our common units at $19.00. The remaining options were settled in October 2012 and additional compensation expense of $1.3 million was recorded, representing the excess of the settlement payment over the fair value of the options at grant date. The additional compensation expense was recognized in the Selling, general and administrative expenses line item in the Consolidated Statement of Operations.

Restricted and Phantom Units

A restricted unit is a unit grant that vests over a period of time and that during such time is subject to forfeiture. A phantom unit grant represents the equivalent of one common unit of the Company. The phantom units, once vested, are settled through the delivery of a number of common units equal to the number of such vested units, or an amount of cash equal to the fair market value of such common units on the vesting date to be paid in a single lump sum payment, as determined by the compensation committee in its discretion. The Compensation Committee may grant tandem distribution equivalent rights (“DERs”) with respect to the phantom units that entitle the holder to receive the value of any distributions made by us on our units while the phantom units are outstanding.

The fair value of restricted unit and phantom unit awards is measured based on the fair market value of the Company units on the date of grant. The values of restricted unit grants and phantom unit grants that are required to be settled in units are recognized as expense over the vesting period of the grants with a corresponding charge to members’ equity. When the Company has the option to settle the phantom unit grants by issuing Company units or through cash settlement, the Company recognizes the value of those grants utilizing the liability method as defined under ASC Topic 718 based on the Company’s historical practice of settling phantom units predominantly in cash. The fair value of liability awards is remeasured at each reporting date through the settlement date with the change in fair value recognized as compensation expense over that period.

Executive Employment Agreements and Annual Bonus

In June and July 2013, we and VNRH entered into new amended and restated executive employment agreements (the "Amended Agreements") with each of our three executive officers. The Amended Agreements were effective January 1, 2013 and the initial term of the Amended Agreements ends on January 1, 2016, with a subsequent twelve-month term extension automatically commencing on January 1, 2016 and each successive January 1 thereafter, provided that neither VNRH nor the executives deliver a timely non-renewal notice prior to a term expiration date.

The Amended Agreements provide for an annual base salary and eligibility to receive an annual performance-based cash bonus award. The annual bonus will be calculated based upon three Company performance components: absolute target distribution growth, adjusted EBITDA growth and relative unit performance to peer group, as well as a fourth component determined solely in the discretion of our board of directors. As of December 31, 2014, an accrued liability was recognized and compensation expense of $1.4 million was recorded for the year ended December 31, 2014, related to these bonus arrangements, which was classified in the selling, general and administrative expenses line item in the Consolidated Statement of Operations.

Under the Amended Agreements, the executives are also eligible to receive annual equity-based compensation awards, consisting of restricted units and/or phantom units granted under the VNR LTIP. The restricted units and phantom units granted to executives under the Amended Agreements are subject to a three-year vesting period. One-third of the aggregate number of the units vest on each one-year anniversary of the date of grant so long as the executive remains continuously employed with the Company. Both the restricted and phantom units include a tandem grant of DERs.

Restricted Unit Grants

On January 1, 2014, the executives were granted a total of 182,377 restricted units in accordance with the Amended Agreements.

During the year ended December 31, 2014, our three independent board members were granted a total of 13,137 restricted units which will vest one year from the date of grant. In addition, VNR employees were granted a total of 96,310 restricted units under the VNR LTIP which will vest three years from the date of grant. The restricted units granted to the board members and VNR employees are accompanied by DERs.

As of December 31, 2014, a summary of the status of the non-vested restricted units under the VNR LTIP is presented below:

	Number of Non-vested Restricted Units		Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2013	248,611		$28.57
Granted	291,824		$29.02
Forfeited	(9,047	)	$29.54
Vested	(91,341	)	$28.48
Non-vested units at December 31, 2014	440,047		$28.87

The weighted average grant-date fair value of restricted units granted was $28.70 and $27.95 during the years ended December 31, 2013 and 2012, respectively.

At December 31, 2014, there was approximately $8.4 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 1.7 years. Our Consolidated Statements of Operations reflects non-cash compensation related to restricted unit grants of $10.7 million, $3.4 million and $4.2 million in the Selling, general and administrative expenses line item for the years ended December 31, 2014, 2013 and 2012, respectively.

Phantom Unit Grants

We did not grant any phantom units during the year ended December 31, 2014.

As of December 31, 2014, a summary of the status of the non-vested phantom units under the VNR LTIP is presented below:

	Number of Non-vested Phantom Units		Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2013	482,735		$28.67
Forfeited	(12,539	)	$28.35
Vested	(139,875	)	$28.92
Non-vested units at December 31, 2014	330,321		$28.58

The weighted average grant-date fair value of phantom units granted was $28.29 and $28.67 during the years ended December 31, 2013 and 2012, respectively.

At December 31, 2014, there was approximately $9.4 million of unrecognized compensation cost related to non-vested phantom units. The cost is expected to be recognized over an average period of approximately 1.7 years. Compensation expense related to phantom units granted to executive officers, board members and employees of $1.0 million, $2.6 million and $1.2 million has been recognized in the selling, general and administrative expense line item in the Consolidated Statements of Operations for the years ended December 31, 2014, 2013, and 2012, respectively.

11. Shelf Registration Statements

We have registered an indeterminate amount of Series A Cumulative Preferred Units, Series B Cumulative Preferred Units, Series C Cumulative Preferred Units, common units, debt securities and guarantees of debt securities under our shelf registration statement filed with the SEC (the "Shelf Registration Statement"), which was effective until January 2015. As discussed in Note 12. Subsequent Events, we filed a new shelf registration statement on February 13, 2015.

Net proceeds, terms and pricing of each offering of securities issued under the Shelf Registration Statement are determined at the time of such offerings. The Shelf Registration Statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the Shelf Registration Statement for the purpose of issuing, from time to time, any combination of equity or debt securities, will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.
We have entered into an equity distribution agreement with respect to the issuance and sale of our Series A Cumulative Preferred Units and common units (the "Equity Distribution Agreement") under our at-the-market equity program. Pursuant to the terms of the equity distribution agreement, we may sell from time to time through our sales agents (i) our common units representing limited liability company interests having an aggregate offering price of up to $500.0 million and (ii) our Series A Cumulative Preferred Units having an aggregate offering price of up to $250.0 million. The common units and Series A Cumulative Preferred Units to be sold under the Equity Distribution Agreement are registered under our existing Shelf Registration Statement. During the year ended December 31, 2014, total net proceeds received under our at-the-market equity program were approximately $147.8 million, after commissions and fees, from the sales of 4,863,690 common units and $1.2 million, after commissions and fees, from the sales of 45,946 Series A Cumulative Preferred Units.

Preferred Unit Equity Offerings

On March 11, 2014, we completed a public offering of 7,000,000 7.625% Series B Cumulative Preferred Units at a price of $25.00 per unit. Offers were made pursuant to a prospectus supplement to the Shelf Registration Statement. We received proceeds of approximately $169.3 million from this offering, after deducting underwriting discounts of $5.5 million and offering costs of $0.2 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

On September 15, 2014, we completed a public offering of 4,000,000 7.75% Series C Cumulative Preferred Units at a price of $25.00 per unit. Offers were made pursuant to a prospectus supplement to the Shelf Registration Statement. We received proceeds of approximately $96.9 million from this offering, after deducting underwriting discounts of $3.2 million and offering costs of $0.2 million. On September 23, 2014, we received additional proceeds of approximately $7.3 million from the sale of an additional 300,000 Series C Cumulative Preferred Units that were purchased pursuant to the underwriters' over-allotment option. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

Subsidiary Guarantors

We and VNR Finance Corp., our wholly-owned finance subsidiary, may co-issue securities pursuant to our effective shelf registration statement. VNR has no independent assets or operations. Debt securities that we may offer may be guaranteed by our subsidiaries. We contemplate that if we offer guaranteed debt securities, the guarantees will be full and unconditional and joint and several, and any subsidiaries of Vanguard that do not guarantee the securities will be minor.

12. Subsequent Events

Distributions

On January 22, 2015, our board of directors declared a cash distribution for our common and Class B unitholders attributable to the month of December 2014 of $0.21 per common and Class B unit ($2.52 on an annualized basis) that was paid on February 13, 2015 to Vanguard unitholders of record on February 2, 2015.

Also on January 22, 2015, our board of directors declared a cash distribution for our preferred unitholders of $0.1641 per Series A Cumulative Preferred Unit, $0.15885 per Series B Cumulative Preferred Unit and $0.16146 per Series C Cumulative Preferred Unit to that was paid on February 13, 2015 to Vanguard preferred unitholders of record on February 2, 2015.

On February 17, 2015, our board of directors declared a cash distribution for our common and Class B unitholders attributable to the month of January 2015 of $0.1175 per common and Class B unit, or $1.41 on an annualized basis, which will be paid on March 17, 2015 to Vanguard unitholders of record on March 2, 2015. This represents a reduction from the distribution attributable to the month of December 2014 of $0.21 per common and Class B unit, or $2.52 on an annualized basis.

Also on February 17, 2015, our board of directors declared and maintained a cash distribution for our preferred unitholders of $0.1641 per Series A Cumulative Preferred Unit, $0.15885 per Series B Cumulative Preferred Unit and $0.16146 per Series C Cumulative Preferred Unit, which will be paid on March 16, 2015 to Vanguard preferred unitholders of record on March 2, 2015.

Shelf Registration Statement

On February 13, 2015, we filed a new shelf registration statement to replace our previous shelf registration statement which expired in January 2015.

Restructured Hedge Portfolio (Unaudited)

We have taken steps to restructure our hedge portfolio to limit further downside and volatility due to the current commodity price environment. Specifically, we have converted a significant portion of our three-way collars in 2015 to fixed-price swaps or lowered the pricing on existing short puts. We have implemented a hedging program for approximately 77% and 45% of our anticipated crude oil production in 2015 and 2016, respectively, with 88% in the form of fixed-price swaps in 2015. Approximately 82% and 67% of our natural gas production in 2015 and 2016, respectively, is hedged with 98% in the form of fixed-price swaps in 2015. NGLs production is under fixed-price swaps for approximately 9% of anticipated production in 2015.

Supplemental Selected Quarterly Financial Information

Financial information by quarter (unaudited) is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(in thousands, except per unit amounts)				
2014					
Oil, natural gas and NGLs sales	$152,740	$161,519	$153,627	$156,727	$624,613
Net gains (losses) on commodity derivative contracts	(56,037)	(38,398)	83,311	174,576	163,452
Total revenues	$96,703	$123,121	$236,938	$331,303	$788,065
Total costs and expenses (1)	$97,103	$110,194	$108,961	$135,907	$452,165
Impairment of oil and natural gas properties	$—	$—	$—	$234,434	$234,434
Net gains on acquisitions of oil and natural gas properties	$32,114	$—	$2,409	$—	$34,523
Net income (loss)	$15,121	$(4,737)	$114,099	$(60,138)	$64,345
Distributions to Preferred unitholders	$(1,962)	$(4,596)	$(4,949)	$(6,690)	$(18,197)
Net income (loss) available to Common and Class B unitholders	$13,159	$(9,333)	$109,150	$(66,828)	$46,148
Net income (loss) per Common & Class B unit:					
Basic	$0.17	$(0.12)	$1.31	$(0.80)	$0.56
Diluted	$0.16	$(0.12)	$1.30	$(0.80)	$0.55
2013					
Oil, natural gas and NGLs sales	$96,682	$116,737	$121,510	$108,319	$443,248
Net gains (losses) on commodity derivative contracts	(29,276)	58,595	(17,714)	(349)	11,256
Total revenues	$67,406	$175,332	$103,796	$107,970	$454,504
Total costs and expenses (1)	$78,757	$86,284	$83,916	$90,452	$339,409
Net gain (loss) on acquisitions of oil and natural gas properties	$—	$5,827	$(236)	$—	$5,591
Net income (loss)	$(27,023)	$81,301	$3,121	$2,112	$59,511
Distributions to Preferred unitholders	$—	$(152)	$(1,240)	$(1,242)	$(2,634)
Net income (loss) available to Common and Class B unitholders	$(27,023)	$81,149	$1,881	$870	$56,877
Net income (loss) per Common & Class B unit:					
Basic	$(0.42)	$1.14	$0.02	$0.01	$0.78
Diluted	$(0.42)	$1.14	$0.02	$0.01	$0.77

(1) Includes lease operating expenses, production and other taxes, depreciation, depletion, amortization and accretion, and selling, general and administration expenses.

Supplemental Oil and Natural Gas Information

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States.

Capitalized Costs Relating to Oil and Gas Producing Activities

Capitalized costs related to oil, natural gas and NGLs producing activities and related accumulated depletion, amortization and accretion were as follows at December 31:

	2014	2013
	(in thousands)	
Aggregate capitalized costs relating to oil, natural gas and NGLs producing activities	$4,140,527	$2,523,671
Aggregate accumulated depletion, amortization and impairment	(1,164,721)	(713,154)
Net capitalized costs	$2,975,806	$1,810,517

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

Costs incurred in oil, natural gas and NGLs producing activities, whether capitalized or expensed, were as follows for the years ended December 31:

	2014	2013	2012
	(in thousands)		
Property acquisition costs	$1,474,841	$332,874	$705,198
Development costs	142,015	56,661	50,405
Total cost incurred	$1,616,856	$389,535	$755,603

No internal costs or interest expense were capitalized in 2014, 2013 or 2012.

Oil and Gas Reserves (Unaudited)

Net quantities of proved developed and undeveloped reserves of oil, natural gas and NGLs and changes in these reserves during the years ended December 31, 2014, 2013 and 2012 are presented below. Estimates of proved reserves at December 31, 2014 were based on studies performed by our internal reserve engineers in accordance with guidelines established by the SEC. Beginning with our 2013 year-end reserves, we engaged DeGolyer and MacNaughton ("D&M"), an independent petroleum engineering firm, to audit a substantial portion of our reserves. Our reserve estimates were based on the reserve reports prepared by D&M and Netherland, Sewell & Associates, Inc. in 2012.

	Gas (in MMcf)	Oil (in MBbls)	NGL (in MBbls)
Net proved reserves			
January 1, 2012	162,830	44,803	7,385
Revisions of previous estimates	(9,513)	(2,540)	53
Extensions, discoveries and other	253	468	7
Purchases of reserves in place	446,141	2,713	12,159
Sales of reserves in place	(33,546)	(468)	—
Production	(19,652)	(2,758)	(664)
December 31, 2012	546,513	42,218	18,940
Revisions of previous estimates	(9,589)	(765)	4,836
Extensions, discoveries and other	13,556	303	343
Purchases of reserves in place	86,245	6,649	6,553
Production	(50,236)	(3,089)	(1,477)
December 31, 2013	586,489	45,316	29,195
Revisions of previous estimates	(66,797)	(2,910)	(10,769)
Extensions, discoveries and other	2,927	465	22
Purchases of reserves in place	1,036,285	12,873	26,840
Sales of reserves in place	—	(2,394)	—
Production	(83,037)	(3,301)	(2,759)
December 31, 2014	1,475,867	50,049	42,529
Proved developed reserves			
December 31, 2012	400,014	37,545	8,391
December 31, 2013	455,162	40,099	18,962
December 31, 2014	970,714	39,143	28,678
Proved undeveloped reserves			
December 31, 2012	146,500	4,673	10,549
December 31, 2013	131,327	5,217	10,233
December 31, 2014	505,153	10,906	13,851

Revisions of previous estimates of reserves are a result of changes in oil and natural gas prices, production costs, well performance and the reservoir engineer's methodology. Our reserves increased by 437.5 Bcfe during the year ended December 31, 2012 due primarily to the Arkoma Basin Acquisition and Rockies Acquisition completed during 2012, offset by the divestiture of our Appalachian properties in the Unit Exchange. Our reserves increased by 120.1 Bcfe during the year ended December 31, 2013 due primarily to the acquisitions completed during 2013. Our reserves increased by 997.8 Bcfe during the year ended December 31, 2014 due primarily to the Pinedale Acquisition and Piceance Acquisition completed during 2014, offset by a revision of previous estimates primarily in the Arkoma Basin attributable to a change in our future development plan as a result of changes in commodity pricing and the production cost environment.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of “reasonable certainty” be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of oil, natural gas and NGLs that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from oil and natural gas properties we own declines as reserves are depleted. Except to the extent we conduct successful development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2014.

Our proved undeveloped reserves at December 31, 2014, as estimated by our internal reserve engineers, were 653.7 Bcfe, consisting of 10.9 MMBbls of oil, 505.2 Bcf of natural gas and 13.8 MMBbls of NGLs. Our proved undeveloped reserves increased by 429.7 Bcfe during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The increase in proved undeveloped reserves during 2014 resulted from an increase of 517.4 Bcfe from acquisitions completed during 2014 and a net increase of 34.6 Bcfe in revisions of previous quantities estimates and changes in prices. The increase is offset by a decrease of 101.2 Bcfe due to revisions in the timing of our drilling development plan primarily in the Arkoma Basin. Additionally, we developed approximately 21.1 Bcfe of our total proved undeveloped reserves booked as of December 31, 2013 through the drilling of 53 gross (6.08 net) wells.

At December 31, 2014, none of our proved undeveloped properties are scheduled to be drilled on a date more than five years from the date the reserves were initially booked as proved undeveloped. Additionally, none of our proved undeveloped reserves at December 31, 2014 have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves.

Results of operations from producing activities were as follows for the years ended December 31:

	2014	2013	2012
	(in thousands)		
Production revenues	$624,613	$443,248	$310,356
Production costs [(1)]	(194,389)	(145,932)	(103,735)
Depreciation, depletion and amortization	(219,255)	(163,122)	(102,518)
Impairment of oil and natural gas properties	(234,434)	—	(247,722)
Results of operations from producing activities	$(23,465)	$134,194	$(143,619)

(1) Production cost includes lease operating expenses and production related taxes, including ad valorem and severance taxes.

The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves at December 31 is as follows:

	2014	2013	2012
	(in thousands)		
Future cash inflows	$11,225,973	$6,670,299	$5,935,790
Future production costs	(3,999,460)	(2,352,721)	(2,110,841)
Future development costs	(845,872)	(358,119)	(386,319)
Future net cash flows	6,380,641	3,959,459	3,438,630
10% annual discount for estimated timing of cash flows	(3,404,914)	(2,125,488)	(1,862,083)
Standardized measure of discounted future net cash flows	$2,975,727	$1,833,971	$1,576,547

For the December 31, 2014, 2013, and 2012 calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using the average oil and natural gas price based upon the 12-month average price of $94.87, $96.90 and $94.67 per barrel of crude oil, respectively, $4.36, $3.67 and $2.76 per MMBtu for natural gas, respectively, adjusted for quality, transportation fees and a regional price differential, and the volume-weighted average price of $35.35, $36.28 and $38.52 per barrel of NGLs. The NGLs prices were calculated using the differentials for each property to a West Texas Intermediate reference price of $94.87, $96.90 and $94.67 for the years ended December 31, 2014, 2013, and 2012, respectively. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

The following are the principal sources of change in our standardized measure of discounted future net cash flows:

	Year Ended December 31, (1)		
	2014	2013	2012
	(in thousands)		
Sales and transfers, net of production costs	$(430,224)	$(297,316)	$(206,621)
Net changes in prices and production costs	11,138	(13,797)	(212,610)
Extensions discoveries and improved recovery, less related costs	24,841	24,110	41,556
Changes in estimated future development costs	36,564	43,496	(16,707)
Previously estimated development costs incurred during the period	68,817	56,661	50,405
Revision of previous quantity estimates	(292,454)	28,462	(73,424)
Accretion of discount	183,397	157,655	147,623
Purchases of reserves in place	1,621,571	333,530	465,217
Sales of reserves in place	(48,163)	—	(40,918)
Change in production rates, timing and other	(33,731)	(75,377)	(54,207)
Net change	$1,141,756	$257,424	$100,314

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Commission. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2014 at the reasonable assurance level.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014, is set forth in Item 9A(b) below.

BDO USA, LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014, as stated in their report in Item 9A(d) below.

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

Our management is responsible for establishing and maintaining effective internal control over financial reporting, as defined by SEC rules adopted under the Exchange Act, as amended. Our internal control over financial reporting is 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. It consists of policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our 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. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 and procedures may deteriorate.

Under the supervision and with the participation of management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014. In making this assessment, we used the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2014. The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by BDO USA, LLP, an independent registered public accounting firm, as stated in their report included herein.

(c) Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

(d) Attestation Report

Report of Independent Registered Public Accounting Firm
on Internal Control over Financial Reporting

Board of Directors and Members
Vanguard Natural Resources, LLC
Houston, Texas

We have audited Vanguard Natural Resources, LLC's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Vanguard Natural Resources, LLC'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 "Item 9A. Controls and Procedures — 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, Vanguard Natural Resources, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Vanguard Natural Resources, LLC as of December 31, 2014 and 2013, and the related consolidated statements of operations, members' equity and cash flows for each of the three years in the period ended December 31, 2014 and our report dated March 2, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
March 2, 2015

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

ITEM 11. EXECUTIVE COMPENSATION

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended

December 31, 2014.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Financial statements

The following consolidated financial statements are included in "Part II—Item 8. Financial Statements and Supplementary Data" of this Annual Report:

(b) Exhibits

The following exhibits are incorporated by reference into the filing indicated or are filed herewith.

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
3.1	Fifth Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC.	Form 8-K, filed September 15, 2014 (File No. 001-33756)
4.1	Indenture, dated as of April 4, 2012, among Vanguard Natural Resources, LLC and VNR Finance Corp., as Issuers, the Subsidiary Guarantors named therein, as Guarantors, and U.S. Bank National Association, as Trustee.	Form 8-K, filed April 4, 2012 (File No. 001-33756)
4.2	First Supplemental Indenture, dated as of April 4, 2012, among Vanguard Natural Resources, LLC and VNR Finance Corp., as Issuers, the Subsidiary Guarantors named therein, as Guarantors, and U.S. Bank National Association, as Trustee.	Form 8-K, filed April 4, 2012 (File No. 001-33756)
4.3	Form of 7.875% Senior Notes due 2020 (incorporated herein by reference to Exhibit A to Exhibit 4.2)	Form 8-K, filed April 4, 2012 (File No. 001-33756)
4.4	Specimen Unit Certificate for the Series A Cumulative Redeemable Perpetual Preferred Units (incorporated herein by reference to Exhibit B to Exhibit 3.2).	Form 8-K, filed March 11, 2014 (File No. 001-33756)
4.5	Specimen Unit Certificate for the Series B Cumulative Redeemable Perpetual Preferred Units (incorporated herein by reference to Exhibit C to Exhibit 3.2).	Form 8-K, filed March 11, 2014 (File No. 001-33756)
4.6	Specimen Unit Certificate for the Series C Cumulative Redeemable Perpetual Preferred Units (incorporated herein by reference to Exhibit D to Exhibit 3.3).	Form 8-K, filed September 15, 2014 (File No. 001-33756)
10.1+	Vanguard Natural Resources, LLC Long-Term Incentive Plan	Form 8-K, filed October 24, 2007 (File No. 001-33756)
10.2+	First Amendment to the Vanguard Natural Resources, LLC Long-Term Incentive Plan	Previously filed with our Quarterly report on Form 10-Q on November 2, 2012 (File No. 001-33756)
10.3+	Form of Vanguard Natural Resources, LLC Long-Term Incentive Plan Phantom Options Grant Agreement	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.4+	Vanguard Natural Resources, LLC Class B Unit Plan	Form 8-K, filed October 24, 2007 (File No. 001-33756)
10.5+	Form of Vanguard Natural Resources, LLC Class B Unit Plan Restricted Class B Unit Grant	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.6	Amended and Restated Indemnity Agreement by and between Nami Resources Company, L.L.C., Vinland Energy Eastern, LLC, Trust Energy Company, LLC, Vanguard Natural Gas, LLC and Vanguard Natural Resources, LLC, dated September 11, 2007	Form S-1/A, filed September 18, 2007 (File No. 333-142363)
10.7		

	Registration Rights Agreement, dated April 18, 2007, between Vanguard Natural Resources, LLC and the private investors named therein	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.8	Purchase Agreement, dated April 18, 2007, between Vanguard Natural Resources, LLC, Majeed S. Nami and the private investors named therein	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.9	Purchase and Sale Agreement, dated November 16, 2010 among Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC, Denbury Resources Inc., Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P.	Form 8-K, filed November 17, 2010 (File No. 001-33756)
10.10	Purchase and Sale Agreement, dated June 22, 2011, by and among Vanguard Permian, LLC and Encore Energy Partners Operating, LLC and EnerVest Institutional Fund X-A, L.P. and EnerVest Institutional Fund X-WI, L.P.	Form 8-K, filed June 23, 2011 (File No. 001-33756)
10.11	Purchase and Sale Agreement, dated June 22, 2011, by and among Vanguard Permian, LLC and Encore Energy Partners Operating, LLC and EV Properties, L.P.	Form 8-K, filed June 23, 2011 (File No. 001-33756)

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
10.12	Agreement and Plan of Merger, dated July 10, 2011, by and among Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC, Vanguard Acquisition Company, LLC, Encore Energy Partners L.P. and Encore Energy Partners GP LLC	Form 8-K, filed July 11, 2011 (File No. 001-33756)
10.13	Unit Exchange Agreement, dated February 21, 2012, among Vanguard Natural Gas, LLC and Vanguard Natural Resources, LLC, and Majeed S. Nami Personal Endowment Trust and Majeed S. Nami Irrevocable Trust	Form 8-K, filed February 29, 2012 (File No. 001-33756)
10.14	Purchase and Sale Agreement, dated June 1, 2012 between Vanguard Permian, LLC and Antero Resources Corporation	Form 8-K, filed June 4, 2012 (File No. 001-33756)
10.15	Purchase and Sale Agreement, dated November 1, 2012 between Encore Energy Partners Operating, LLC and Bill Barrett Corporation.	Form 8-K, filed November 5, 2012 (File No. 001-33756)
10.16	Purchase and Sale Agreement, dated November 9, 2012 between Encore Energy Partners Operating, LLC and Halliburton Energy Services, Inc.	Form 8-K, filed November 15, 2012 (File No. 001-33756)
10.17	Purchase and Sale Agreement, dated February 26, 2013 among Vanguard Permian, LLC and Range Resources Corporation	Form 8-K, filed March 4, 2013 (File No. 001-33756)
10.18	Purchase and Sale Agreement, dated December 23, 2013 among Encore Energy Partners Operating, LLC and Anadarko E&P Onshore LLC.	Form 8-K, filed December 30, 2013 (File No. 001-33756)
10.19+	Director Compensation Agreement	Form S-1/A, filed September 18, 2007 (File No. 333-142363)
10.20+	Form of Indemnity Agreement dated August 7, 2008	Previously filed with our Quarterly report on Form 10-Q on August 13, 2008 (File No. 001-33756)
10.21	Registration Rights Agreement, dated December 31, 2010, by and between Vanguard Natural Resources, LLC and Encore Operating, L.P.	Form 8-K, filed January 3, 2011 (File No. 001-33756)
10.22	Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, by and among Vanguard Natural Gas, LLC, Denbury Resources Inc., Encore Energy Partners GP LLC, Encore Energy Partners LP, Encore Operating, L.P. and Encore Energy Partners Operating LLC	Form 8-K, filed January 3, 2011 (File No. 001-33756)
10.23	Voting Agreement dated as of July 10, 2011, by and among Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC, Vanguard Acquisition Company, LLC, Encore Energy Partners GP LLC and Encore Energy Partners LP.	Form 8-K, filed July 11, 2011 (File No. 001-33756)
10.24	Confidentiality Agreement, dated April 27, 2011, by and among Vanguard Natural Resources, LLC, the Conflicts Committee of the Board of Directors of	Form S-4/A, filed September 6, 2011 (File No. 333-175944)

	Encore Energy Partners GP LLC and Encore Energy Partners GP LLC.	
10.25	Standstill Agreement, dated April 29, 2011, by and between Vanguard Natural Resources, LLC and the Conflicts Committee of the Board of Directors of Encore Energy Partners GP LLC.	Form S-4/A, filed September 6, 2011 (File No. 333-175944)
10.26	Third Amended and Restated Credit Agreement dated September 30, 2011, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party hereto	Form 8-K, filed October 5, 2011 (File No. 001-33756)

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
10.27	First Amendment, dated November 30, 2011, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party hereto.	Form 8-K, filed December 2, 2011 (File No. 001-33756)
10.28	Second Amendment, dated June 29, 2012, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto	Form 8-K, filed July 10, 2012 (File No. 001-33756)
10.29	Third Amendment, dated December 31, 2012, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto	Previously filed with our Annual Report on Form 10-K on March 31, 2013 (File No. 001-33756)
10.30	Fourth Amendment, dated April 16, 2013, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto	Previously filed with our Quarterly report on Form 10-Q on August 1, 2013 (File No. 001-33756)
10.31	Fifth Amendment, dated November 5, 2013, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto	Previously filed with our Annual Report on Form 10-K on February 28, 2014 (File No. 001-33756)
10.32	Sixth Amendment, dated April 30, 2014, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto	Form 8-K, filed May 2, 2014 (File No. 001-33756)
10.33	Seventh Amendment, dated October 30, 2014, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto	Filed herewith
10.34	Term Loan Agreement, dated November 30, 2011, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party hereto.	Form 8-K, filed December 2, 2011 (File No. 001-33756)
10.35+	Phantom Unit Award Agreement, dated August 1, 2012, by and between Vanguard Natural Resources, LLC, and Scott W. Smith	Form 8-K, filed August 6, 2012 (File No. 001-33756)
10.36+	Phantom Unit Award Agreement, dated August 1, 2012, by and between Vanguard Natural Resources, LLC, and Richard Robert	Form 8-K, filed August 6, 2012 (File No. 001-33756)
10.37+	Phantom Unit Award Agreement, dated August 1, 2012, by and between Vanguard Natural Resources,	Form 8-K, filed August 6, 2012 (File No. 001-33756)

	LLC, and Britt Pence	
10.38+	Amended and Restated Employment Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC and Scott W. Smith	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.39+	Amended and Restated Employment Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC and Richard A. Robert	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.40+	Form of Restricted Unit Award Agreement	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.41+	Form of Phantom Unit Award Agreement	Form 8-K, filed June 12, 2013 (File No. 001-33756)
10.42+	Amended and Restated Employment Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC and Britt Pence	Form 8-K, filed July 11, 2013 (File No. 001-33756)
10.43+	Form of Restricted Unit Award Agreement	Form 8-K, filed July 11, 2013 (File No. 001-33756)
10.44+	Form of Phantom Unit Award Agreement	Form 8-K, filed July 11, 2013 (File No. 001-33756)
10.45	Purchase and Sale Agreement, dated July 30, 2014 among Vanguard Permian, LLC and Hunt Oil Company	Form 8-K, filed August 7, 2014 (File No. 001-33756)

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
10.46	First Amendment To Purchase and Sale Agreement and Assignment, dated August 29, 2014 among Vanguard Permian, LLC, Vanguard Operating, LLC and Hunt Oil Company and Hunt Oil Company of Louisiana, Inc.	Form 8-K/A, filed September 4, 2014 (File No. 001-33756)
10.47	Purchase and Sale Agreement, dated September 15, 2014 among Vanguard Operating, LLC and Bill Barrett Corporation	Form 8-K, filed September 16, 2014 (File No. 001-33756)
12.1	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Unit Distributions	Filed herewith
21.1	List of subsidiaries of Vanguard Natural Resources, LLC	Filed herewith
23.1	Consent of BDO USA, LLP, Independent Registered Public Accounting Firm	Filed herewith
23.2	Consent of DeGolyer and MacNaughton	Filed herewith
24.1	Power of Attorney (included on signature page hereto)	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a - 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a - 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith
99.1	Report of DeGolyer and MacNaughton, Independent Petroleum Engineers and Geologists	Filed herewith
101.INS	XBRL Instance Document	Filed herewith
101.SCH	XBRL Schema Document	Filed herewith
101.CAL	XBRL Calculation Linkbase Document	Filed herewith
101.DEF	XBRL Definition Linkbase Document	Filed herewith
101.LAB	XBRL Label Linkbase Document	Filed herewith
101.PRE	XBRL Presentation Linkbase Document	Filed herewith

+ Management Contract or Compensatory Plan or Arrangement required to be filed as an exhibit hereto pursuant to item 601 of Regulation S-K.

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 on the 2nd day of March, 2015.

VANGUARD NATURAL RESOURCES, LLC
/s/ Scott W. Smith
Scott W. Smith
President and Chief Executive Officer

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Scott W. Smith and Richard A. Robert, and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this Annual Report on Form 10-K, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

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.

March 2, 2015	/s/ Scott W. Smith Scott W. Smith President, Chief Executive Officer and Director (Principal Executive Officer)
March 2, 2015	/s/ Richard A. Robert Richard A. Robert Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
March 2, 2015	/s/ W. Richard Anderson W. Richard Anderson Director
March 2, 2015	/s/ Bruce W. McCullough Bruce W. McCullough Director
March 2, 2015	/s/ Loren Singletary Loren Singletary Director

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