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Rice Energy Inc.
Form 10-K
March 13, 2015

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

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2014

or

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

For the transition period from _____ to _____

Commission File Number: 001-36273

Rice Energy Inc.

(Exact name of registrant as specified in its charter)

Delaware

46-3785773

(State or other jurisdiction of incorporation or organization)

(I.R.S. Employer Identification No.)

400 Woodcliff Drive

15317

Canonsburg, Pennsylvania

(Address of principal executive offices)

(Zipcode)

Registrant's telephone number, including area code: (724) 746-6720

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

Title of each class

Name of each exchange on which registered

Common Stock, par value \$0.01 per share

New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements

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incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. "

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

Large accelerated filer "

Accelerated filer "

Non-accelerated filer

Smaller reporting company "

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

"Yes No

The aggregate market value of the equity held by non-affiliates of the registrant as of June 30, 2014: \$1,612,534,986

The number of shares of common stock outstanding as of March 10, 2015: 136,297,909

Documents Incorporated by Reference

The Company's definitive proxy statement relating to the annual meeting of shareholders (to be held June 3, 2015) will be filed with the Commission within 120 days after the close of the Company's fiscal year ended December 31, 2014 and is incorporated by reference in Part III to the extent described herein.

RICE ENERGY INC.
ANNUAL REPORT ON FORM 10-K
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Emerging Growth Company Status

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

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

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

- the last day of the fiscal year in which we have \$1.0 billion or more in annual revenues;
- the date on which we become a “large accelerated filer” (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is \$700 million or more as of June 30);
- the date on which we issue more than \$1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

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

Cautionary Statement Regarding Forward-Looking Statements

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

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, natural gas liquid (“NGL”) and oil prices;
- timing and amount of future production of natural gas, NGLs and oil;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs and oil;
- leasehold or business acquisitions;
- costs of developing our properties and conducting our gathering and other midstream operations;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

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

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered. Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

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

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

Commonly Used Defined Terms

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

- “Rice Energy,” the “Company,” “we,” “our,” “us” or like terms refer collectively to Rice Energy Inc. and its consolidated subsidiaries, including Rice Drilling B LLC;
- “Rice Drilling B” refers to Rice Drilling B LLC, a wholly-owned subsidiary of Rice Energy;
- “Rice Partners” refers to Rice Energy Family Holdings, LP (formerly known as Rice Energy Limited Partners), an entity affiliated with members of the Rice family;
- “Rice Holdings” refers to Rice Energy Holdings LLC;
- “RMP” refers to Rice Midstream Partners LP (NYSE: RMP);
- “Rice Midstream OpCo” refers to Rice Midstream OpCo LLC, a wholly-owned subsidiary of RMP;
- “Midstream Holdings” refers to Rice Midstream Holdings LLC, a wholly-owned subsidiary of Rice Energy;
- “Rice Appalachia” refers to Rice Energy Appalachia, LLC, the parent company of Rice Drilling B prior to our initial public offering;
- “Alpha Holdings” refers to Foundation PA Coal Company, LLC, a wholly-owned indirect subsidiary of Alpha Natural Resources, Inc.;
- “Marcellus joint venture” refers collectively to Alpha Shale Resources, LP and its general partner, Alpha Shale Holdings, LLC;
- “Natural Gas Partners” refers to a family of private equity investment funds organized to make direct equity investments in the energy industry, including the funds invested in us; and
- “NGP Holdings” refers to NGP Rice Holdings, LLC.

PART I

Item 1. Business

General

Rice Energy Inc., a Delaware corporation, is an independent natural gas and oil company engaged in the acquisition, exploration and development of natural gas, oil and NGL properties in the Appalachian Basin. We operate in two business segments, which are managed separately due to their distinct operational differences. Our two reporting segments are as follows:

Exploration and Production - This segment is engaged in the acquisition, exploration and development of natural gas, oil and NGLs.

Midstream - This segment is engaged in the gathering and compression of natural gas, oil and NGL production of, and in the provision of water services to support the well completion activities of Rice Energy and third-parties.

Our corporate offices are located at 400 Woodcliff Drive, Canonsburg, Pennsylvania 15317 (telephone: (724) 746-6720). Our common stock is listed and traded on the New York Stock Exchange (the "NYSE") under the symbol "RICE." At December 31, 2014, we had 136,280,766 shares outstanding.

Significant Accomplishments in 2014

• Completed successful Rice Energy initial public offering ("IPO"), providing \$593.6 million of net proceeds

• Strategically acquired Marcellus Shale gas gathering assets for \$111.4 million

• Issued \$900.0 million of senior notes due 2022 at 6.25%

• Produced 97.7 Bcfe during 2014, a 325% increase above 2013 production

• Proved reserves increased 242% to 1.3 Tcfe, compared to year end 2013

• Completed first Utica Shale well, which tested at 42 MMcfe/d

• Opportunistically acquired approximately 22,000 net acres in Greene County, Pennsylvania in August 2014, partially funded with net proceeds of \$196.3 million from our follow on equity offering

• Significantly expanded leasehold position by 57% to approximately 141,000 net acres as of year end 2014

• Completed successful initial public offering of Rice Midstream Partners LP (NYSE: RMP) in December 2014 providing net proceeds of \$444.1 million

Background on Our Financial Information and Results of Operations

On January 29, 2014, we completed our IPO and related transactions, including our reorganization and concurrent acquisition of Alpha Holdings' 50% interest in our Marcellus joint venture. On December 22, 2014, RMP completed its IPO and related transactions, including our contribution to it of certain gas gathering and compression assets.

As a result of the reorganizations that occurred during 2014, our historical financial condition and results of operations for the periods presented in this Annual Report may not be comparable, either from period to period or going forward. For example, information for the period from January 1, 2014 until January 29, 2014, as contained within the year ended December 31, 2014, and for the years ended December 31, 2013 and 2012, pertain to the historical financial statements and results of operations of our accounting predecessor. Such periods reflect only our 50% equity investment in our Marcellus joint venture. From and after our acquisition of the remaining 50% interest from Alpha Holdings on January 29, 2014, the results of operations of our Marcellus joint venture are consolidated into our results of operations.

In connection with the RMP IPO in December 2014, we contributed all of our gas gathering and compression assets in Washington and Greene Counties, Pennsylvania in exchange for, among other things, common and subordinated units representing a 50.0% limited partner interest and all of the incentive distribution rights in RMP. Indirectly through Midstream Holdings, we own and control the general partner of RMP, and as such the results of operations of RMP are consolidated into our results of operations. However, while our results of operations consolidate the results of operations of RMP, for the period

from December 22, 2014 until December 31, 2014, as contained within the year ended December 31, 2014, they give effect to the noncontrolling interest in RMP held by its public unitholders.

Also in connection with the RMP IPO, we entered into various gas gathering and compression agreements and water distribution services agreements, both intercompany and, in the case of certain gas gathering and compression services in Pennsylvania, with RMP. Prior to December 22, 2014, with certain limited exceptions, our Midstream segment did not charge fees for providing such services to our Exploration and Production segment.

Exploration and Production Business Segment

Our Exploration and Production segment operates in what we believe to be the core of the Marcellus and Utica Shales. As of December 31, 2014, we held approximately 86,000 net acres in the southwestern core of the Marcellus Shale, substantially all of which are in Washington and Greene Counties, Pennsylvania. We established our Marcellus Shale acreage position through a combination of largely contiguous acreage acquisitions in 2009 and 2010 and through numerous bolt-on acreage acquisitions. In 2012, we acquired approximately 33,000 of our 55,000 net acres in the southeastern core of the Utica Shale, primarily in Belmont County, Ohio. We believe this area to be the core of the Utica Shale based on our and publicly available drilling results. We operate a substantial majority of our acreage in the Marcellus Shale and a majority of our acreage in the Utica Shale.

The following table provides a summary of our approximate net acreage, net drilling locations and net producing wells as of December 31, 2014, average net daily production for the three months ended December 31, 2014, projected 2015 net wells online and projected 2015 drilling and completion (“D&C”) capital budget as of March 12, 2015:

	Approximate Net Acreage	Net Drilling Locations ⁽¹⁾	Net Producing Wells	Q4 2014 Average Net Daily Production (MMcfe/d)	2015 Projected Net Wells Online	2015 Projected D&C Capex Budget (\$mm)
Marcellus Shale	86,000	495	78	336	26	\$340
Utica Shale ⁽²⁾	55,000	356	7	58	10	⁽³⁾ 220
Upper Devonian Shale	77,000	382	3	3	—	—
Total ⁽⁴⁾	141,000	1,233	88	397	36	\$560

Based on our reserve report as of December 31, 2014, we had 62 net drilling locations in the Marcellus Shale associated with proved undeveloped reserves and 10 net drilling locations in the Marcellus Shale associated with proved developed not producing reserves and we had four net drilling locations in the Utica Shale associated with proved undeveloped reserves and one net drilling location in the Utica Shale associated with proved developed not producing reserves. Please see “Item 2. Properties—Exploration and Production Properties Reserve

- (1) Data—Determination of Drilling Locations” for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see “Item 1A. Risk Factors—Risks Related to Our Business—Our drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill our drilling locations.”

- (2) Utica Shale net drilling locations gives effect to our projected 61.8% working interest in the Utica Shale after applying unitization and participating interest assumptions described under “Item 2. Properties—Exploration and Production Properties Reserve Data—Determination of Drilling Locations.”

- (3) Includes one Utica Shale well in Pennsylvania.

- (4) The 77,000 net acres in the Upper Devonian Shale is not included in the total acreage as the Upper Devonian and the Marcellus Shale are stacked formations within the same geographic footprint.

The following table provides certain operational data related to our proved developed producing Marcellus wells as of December 31, 2014. We are the operator of each of these wells.

Year(s)	Gross Operated Wells Turned Into Sales	Average Lateral Length (Feet)	Periodic Flow Rates (MMcfe/d) ⁽¹⁾				D&C (\$/Foot) ⁽²⁾
			0-90	91-180	181-360	361-720	
2010-2011	6	3,281	5.7	6.0	4.4	2.7	\$2,377
2012	9	5,731	9.2	10.0	6.8	4.2	1,660
2013	22	6,286	11.2	10.6	7.6	5.9	1,476
2014 ⁽³⁾	41	7,282	11.2	10.3	5.8	N/A	1,176
Total	78	6,515	10.5	9.9	6.8	3.8	\$1,409

(1)Based on production data through March 1, 2015.

(2)D&C costs are shown gross of our working interest's proportionate share.

(3)Excludes seven producing wells acquired in our Greene County, Pennsylvania acreage acquisition in August 2014. Additionally, we have drilled and completed three Upper Devonian horizontal wells on our Marcellus Shale acreage with a 100% success rate. Based on our Upper Devonian wells and those of other operators in the vicinity of our acreage as well as other geologic data, we estimate that a substantial majority of our Marcellus Shale acreage in southwestern Pennsylvania is prospective for the slightly shallower Upper Devonian Shale. As of December 31, 2014, we had 382 net drilling locations in the Upper Devonian Shale.

We applied the same shale analysis and acquisition strategy that we developed and employed in the Marcellus Shale to acquire our acreage in the Utica Shale in Ohio. In June 2014, we completed our first Utica well in Belmont County, the Bigfoot 9H. As of December 31, 2014, the Bigfoot 9H had cumulatively produced 2.8 Bcf of natural gas. In early December, we increased the restricted flow rate to approximately 16 MMcfe/d from 14 MMcfe/d. During the third quarter of 2014, we turned two additional operated Utica wells into sales at a restricted rate of 16 MMcfe/d. As of December 31, 2014, we had 23 gross (7 net) Utica wells producing, including 3 gross (2 net) operated wells. As of December 31, 2014, we had 356 net Utica Shale drilling locations.

During 2014, we turned 44 gross (39 net) wells into sales and achieved record sales volumes of 97,737 MMcfe, representing a 325% increase in production over the prior year. In addition, we increased our leasehold position in the Marcellus and Utica Shales to approximately 86,000 and 55,000 net acres as of December 31, 2014, representing a 98% and 18% increase over the prior year, respectively. We achieved this growth in acreage through organic leasing efforts, our January 2014 acquisition of the remaining 50% interest in our Marcellus joint venture in exchange for total consideration in the form of cash and stock of \$322 million and our August 2014 acquisition of approximately 22,000 net acres and 12 developed (7 producing) wells in the Marcellus Shale in Greene County, Pennsylvania for approximately \$329.5 million. As of December 31, 2014, we had 1,306.6 Bcfe of proved reserves (49% proved developed and 100% natural gas), representing a 117% increase over the prior year.

In 2015, we plan to invest \$680.0 million in our Exploration and Production segment as follows:

\$340.0 million for drilling and completion in the Marcellus Shale;

\$220.0 million for drilling and completion in the Utica Shale; and

\$120.0 million for leasehold acquisitions.

Our capital budget excludes acquisitions, other than leasehold acquisitions. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

As of March 1, 2015, our average annual firm transportation contracts and firm sales arrangements are approximately 813,000 MMBtu/d in 2015, 918,000 MMBtu/d in 2016 and 1,011,000 MMBtu/d in 2017. These amounts include approximately 115,000 MMBtu/d of firm sales contracted with a third party through October 2017, subject to annual renewal. Under firm transportation contracts, we are obligated to pay demand charges for the contracted capacity regardless of whether it is utilized. We continue to actively identify and evaluate additional takeaway capacity to facilitate production growth in our Appalachian Basin position.

In October 2013, we entered into a Development Agreement and an AMI Agreement with Gulfport Energy Corporation (“Gulfport”) covering approximately 50,000 aggregate net acres in the Utica Shale in Belmont County, Ohio. We refer to these agreements as our “Utica Development Agreements.” Pursuant to the Utica Development Agreements, we have an approximately 68.7% participating interest in acreage currently owned or to be acquired by us or Gulfport located within Goshen and Smith Townships (the “Northern Contract Area”) and approximately 48.2% participating interest in acreage currently owned or to be acquired by us or Gulfport located within Wayne and Washington Townships (the “Southern Contract Area”), each within Belmont County, Ohio. The remaining participating interests are held by Gulfport. The participating interests of us and Gulfport in each of the Northern and Southern Contract Areas approximate our current relative acreage positions in each area.

Pursuant to the Development Agreement, we are named the operator (or Gulfport will agree to vote in favor of our operatorship) of drilling units located in the Northern Contract Area, and Gulfport is named the operator (or we will agree to vote in favor of its operatorship) of drilling units located in the Southern Contract Area. Upon development of a well on the subject acreage, we and Gulfport will convey to one another, pursuant to a cross conveyance, a working interest percentage equal to the amount of the underlying working interest multiplied by the applicable participating interest. As wells are developed in the respective contract area, our average working interests in the Utica Shale will decrease as the applicable participating interests are applied to the developed wells.

For the year ended December 31, 2014, our Exploration and Production segment represented 99% of our operating revenues.

Midstream Business Segment

Our Midstream segment invests in infrastructure to complement our Exploration and Production activities. Through ownership and operation of this infrastructure, we are able to improve our ability to manage costs, control the timing of bringing new production online, and enhance the value received for gathering and compressing our production and providing water services to our well completions operations. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production.

Following the completion of its initial public offering on December 22, 2014, our midstream activities include Rice Midstream Partners LP (NYSE: RMP), which is a publicly traded limited partnership formed to own, operate, develop and acquire midstream assets in the Appalachian Basin and which currently owns our Washington and Greene County gas gathering systems. At December 31, 2014, we owned an approximate 50% limited partner interest and all of the incentive distribution rights in RMP, whose results are consolidated in our financial statements. Unless otherwise noted, discussions of our Midstream business, operations and results in this Annual Report include RMP’s business, operations and results. We record the non-controlling interest of the limited partners of RMP in our consolidated financial statements.

Our midstream assets consist of gathering systems and associated compression infrastructure in Washington and Greene Counties, Pennsylvania (owned by RMP), and gathering systems and associated compression infrastructure in Belmont County, Ohio, and fresh water distribution systems in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. The following table provides information regarding our gathering and compression assets for the periods presented.

	Three Months Ended	As of December 31, 2014		
	December 31, 2014	Pipeline	Capacity	Compression
	Average Daily	(miles)	(MDth/d)	Capacity (HP)
	Throughput (MDth/d)			
RMP:				
Washington County System	351	71	2,772	7,320
Greene County System	166	10	420	—
Rice Energy:				
Belmont County System	74	21	525	—
Total	591	102	3,717	7,320

During 2014, we continued the build-out of our Pennsylvania gathering systems and initiated the build-out of our Ohio gathering system. In April 2014, we acquired a 28-mile, 6- to 16-inch gathering in eastern Washington County, Pennsylvania, and permits necessary to construct an 18-mile, 30-inch gathering pipeline connecting this system to the Texas Eastern Pipeline for approximately \$111.4 million. The acquired system is supported by long-term contracts with acreage dedications covering

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approximately 21,000 acres from third parties. In November 2014, we completed construction of the 18-mile, 30-inch gathering pipeline.

We are also in the process of expanding three fresh water distribution systems that are expected to have direct access to approximately 25.9 MMGPD of fresh water from the Monongahela and Ohio Rivers and other regional sources. These systems service the well completion operations of our Exploration and Production segment.

In 2015, we plan to invest \$390.0 million in our Midstream segment, which includes \$180.0 million expected to be invested by RMP. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Segment Information

For additional information on operations by segment including, but not limited to, revenues from external customers, operating income and total assets, see Note 8 in the notes to consolidated financial statements under Item 8 of this Annual Report.

Markets and Customers

Exploration and Production Segment

Our Exploration and Production segment sells produced natural gas principally to natural gas marketers. Natural gas is a commodity and therefore we receive market-based pricing. The market price for natural gas can be volatile as demonstrated by significant declines in late 2014 and early 2015. In addition, the market price for natural gas in the Appalachian Basin experienced a decline relative to the price at Henry Hub, which is the location for pricing NYMEX and natural gas futures, in the second half of 2013 and 2014 as a result of the increased supply of natural gas in the Northeast region. While additional takeaway capacity has been and continues to be added to alleviate this supply/demand imbalance, the cost of new firm transportation projects has risen significantly in recent years. Changes in the market price for natural gas, including basis, impact our revenues, earnings and liquidity. We are unable to predict potential future movements in the market price for natural gas, including Appalachian basis differentials, and thus cannot predict the ultimate impact of prices on our operations; however, we monitor the market for natural gas and adjust strategy and operations as deemed to be appropriate. In order to protect cash flow from undue exposure to the risk of changing commodity prices, we hedge a portion of our forecasted natural gas production, most of which is hedged at NYMEX natural gas prices.

Our hedging strategy and information regarding our derivative instruments is set forth in “Commodity Hedging Activities” in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” and in Note 4 to the consolidated financial statements in Item 8 of this Annual Report.

For the year ended December 31, 2014, sales to Sequent Energy Management, LP (“Sequent”) represented 79% of our total sales. Although a substantial portion of production is purchased by this major customer, we do not believe the loss of this customer would have a material adverse effect on our business, as other customers or markets would be accessible to us. However, if we lose this customer, there is no guarantee that we will be able to enter into an agreement with a new customer which is as favorable as our current agreements.

Midstream Segment

Our Midstream segment derives gathering and compression revenues from charges to customers for use of its gathering systems and compression assets in Pennsylvania and Ohio. The gathering systems volumes are transported to six major interstate pipelines: Dominion Transmission, EQT Midstream, Columbia Gas Transmission, Texas Eastern Transmission, Natural Fuel Gas Supply and Dominion East Ohio.

Gathering system throughput volumes for 2014 totaled 402 MDth/d, of which approximately 90% related to gathering for our Exploration and Production segment and 10% related to third-party volumes. Prior to December 22, 2014, our Midstream segment did not charge fees for gathering and compression services provided to our Exploration and Production segment. As such, for 2014, our Exploration and Production segment accounted for only 24% of our natural gas gathering and compression revenues. Three third-party customers represented 60% and 96% of our Midstream segment gathering and compression revenues, respectively, for 2014.

Seasonality

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

Seasonal anomalies of the nature described above can increase demand for midstream services during the summer and winter months and decrease demand for such services during the spring and fall months.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration

activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Our Midstream segment faces competition in attracting third-party volumes to our gathering and compression systems. In addition, these third parties may develop their own gathering and compression systems in lieu of employing our assets. Our ability to attract such third-party volumes to our gathering and compression systems depends on our ability to evaluate and select suitable projects and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in attracting third-party volumes to our gathering and compression systems, attracting and retaining quality personnel, and raising additional capital, which could have a material adverse effect on our Midstream segment.

Regulation of the Oil and Natural Gas Industry

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

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (“FERC”), and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Natural Gas and Oil

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

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

We own interests in properties located onshore in two U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of

drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas.

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

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act, or NGPA, and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations. Beginning in 1992, FERC issued a series of orders to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The Energy Policy Act of 2005, or EAct 2005, is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EAct 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EAct 2005 provides FERC with the power to assess civil penalties of up to \$1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from \$5,000 per violation per day to \$1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EAct 2005. The rules make it unlawful: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at

wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

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We cannot accurately predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act, or CEA, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

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

Regulation of Pipeline Safety and Maintenance

The Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), and Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPESA"), govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the DOT has promulgated regulations governing, among other things, pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has established promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. We believe that our pipeline operations are in substantial compliance with applicable requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, measures to ensure future

compliance could result in increased costs.

These pipeline safety laws were amended on January 3, 2012, when President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“2011 Pipeline Safety Act”), which requires increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines, and operator verification of

records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from \$100,000 to \$200,000 per violation per day of violation and also from \$1 million to \$2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of PHMSA guidance with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any of which could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. However, we do not expect that any such costs would be material to our financial condition or results of operations. We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking and sought public comment on a number of proposed changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 report to Congress from the U.S. Government Accountability Office (“GAO”), the GAO acknowledged PHMSA’s continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. We cannot predict what future action the DOT will take, but we do not believe that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas gatherers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

General

Our operations are subject to numerous federal, regional, state, local, and other laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), the Clean Water Act (“CWA”) and the Clean Air Act (“CAA”). These laws and regulations govern environmental cleanup standards, require permits for air emissions, water discharges, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, EPA’s 2014 – 2016 National Enforcement Initiatives include “Assuring Energy Extraction Activities Comply with Environmental Laws.” According to the EPA’s website,

“some techniques for natural gas extraction pose a significant risk to public health and the environment.” To address these concerns, the EPA’s goal is to “address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment.” The EPA has emphasized that this initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

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

Hazardous Substances and Wastes

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

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

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials (“NORM”) may affect our operations. For example, the Pennsylvania Department of Environmental Protection has asked operators to identify technologically enhanced NORM (“TENORM”) in their processes, such as hydraulic fracturing sand. Local landfills only accept such waste when it meets their TENORM permit standards. As a result, we may have to locate out-of-state landfills to accept TENORM waste from time to time, potentially increasing our disposal costs.

Some of our leases may have had prior owners who commenced exploration and production of natural gas and oil operations on these sites. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes were not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA, and/or analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Waste Discharges

The CWA and its state analog impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into

regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Federal spill prevention, control and countermeasure requirements require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. We believe that we maintain all required permits and/or authorizations necessary to conduct our operations, and we further believe we are in substantial compliance with the terms thereof. Federal and state regulatory agencies can impose

administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Air Emissions

The CAA and state analogs and regulations restrict the emission of air pollutants from many sources, including oil and gas facilities. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs to remain in compliance. Over time more stringent regulations governing emissions of toxic air pollutants and greenhouse gases (GHGs) have been developed by the EPA and may increase the costs of compliance for some facilities. In 2012, the EPA issued federal regulations affecting our operations under the New Source Performance Standards provisions (new Subpart OOOO) and expanded regulations under national emission standards for hazardous air pollutants. On December 19, 2014, the EPA finalized amendments and clarifications to the NSPS rules, including, for example, updates and clarifications to requirements related to well completion, storage tanks, and leak detection. In addition, the Obama Administration is expected to release a series of new regulations affecting the oil and gas industry in 2015, including regulations limiting methane emissions from certain new and modified oil and gas facilities. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Oil Pollution Act

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

National Environmental Policy Act

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

Endangered Species Act and Migratory Bird Treaty Act

The Endangered Species Act (“ESA”) and state analogs restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds we believe that we are in substantial compliance with such law. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Worker Safety

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

Safe Drinking Water Act

The Safe Drinking Water Act (“SDWA”) and comparable state provisions restrict the disposal of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state’s environmental authority. These regulations, and any amendments to these regulations, may increase the costs of compliance for some facilities. Furthermore, in response to alleged seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, some agencies have imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase.

Employees

As of December 31, 2014, we had 290 full-time employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We utilize the services of independent contractors to perform various field and other services.

Available Information

Our website is available at <http://www.riceenergy.com>. Information contained on or connected to our website is not incorporated by reference into this Annual Report and should not be considered part of this report or any other filing we make with the U.S. Securities and Exchange Commission (“SEC”). We make available, free of charge, on our website, the annual report 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 filing such reports with the SEC. Other information such as presentations, our Corporate Governance Guidelines, the charters of the Audit Committee, the Compensation Committee and the Nominating and Governance Committee, and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 400 Woodcliff Drive, Canonsburg, Pennsylvania 15317. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the Chief Executive Officer and Chief Financial Officer. The public may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Rice Energy, that file electronically with the SEC. The public can obtain any document we file with the SEC at <http://www.sec.gov>.

Item 1A. Risk Factors

Investing in our common stock involves risks. You should carefully consider the information in this Annual Report, including the matters addressed under “Cautionary Statement Regarding Forward-Looking Statements,” and the following risks before making an investment decision. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to Our Business

Natural gas, NGL and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our natural gas, NGL and oil production heavily influence our revenue, operating results profitability, access to capital, future rate of growth and carrying value of our properties. Natural gas, NGLs and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. For example, the Henry Hub spot market price had declined from a high of \$7.94 per MMBtu on March 5, 2014 to a low of \$2.75 per MMBtu on December 25, 2014. Natural gas prices have remained depressed thus far in 2015, and the commodities market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions affecting the global supply of and demand for natural gas, NGLs and oil;

the price and quantity of imports of foreign natural gas, including liquefied natural gas;

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

Furthermore, the worldwide financial and credit crisis in recent years reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide, resulting in a slowdown in economic activity and recession in parts of the world. This economic environment reduced worldwide demand for energy and resulted in lower natural gas, NGL and oil prices.

In addition, substantially all of our natural gas production is sold to purchasers under contracts with market-based prices. The actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of location differentials. Location differentials to NYMEX Henry Hub prices, also known as basis differentials, result from variances in regional natural gas prices compared to NYMEX Henry Hub prices as a result of regional supply and demand factors. Historically, we have entered into long-term firm transportation arrangements pursuant to which our production is shipped to markets that we expect to be less impacted by basis differentials. In recent years, the cost of new firm transportation projects has risen significantly. There can be no assurance that the net impact of entering into such arrangements, after giving effect to their costs, will result in more favorable sales prices for our production in the future than local pricing. As such, our net sales prices may be materially less than NYMEX Henry Hub prices as a result of basis differentials and/or firm transportation costs.

Lower commodity prices and negative increases in our differentials will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

If commodity prices further decrease or our negative differentials further increase, a significant portion of our development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in commodity prices or an increase in our negative differentials may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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

The natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the development and acquisition of natural gas reserves. In 2015, we plan to invest \$1,070.0 million in our operations,

including \$340.0 million for drilling and completion in the Marcellus Shale, \$220.0 million for drilling and completion in the Utica Shale, \$120.0 million for leasehold acquisitions and \$390.0 million for midstream infrastructure development, including \$180.0 million expected to be invested by RMP. Our capital budget excludes acquisitions, other than leasehold acquisitions. We expect to fund our 2015 capital expenditures with existing cash, cash generated by operations and borrowings under our revolving credit facilities. If we do not have sufficient borrowing availability under our revolving credit facilities, including our \$550.0 million Senior Secured Revolving Credit Facility (“Senior Secured Revolving Credit Facility”) due to the current commodity price environment or otherwise, we may seek alternate debt financing or reduce our capital expenditures. In addition, a portion of our 2015 capital budget is projected to be financed with cash flows from operations derived from wells drilled on drilling locations not associated with proved reserves in our reserve report. The failure to achieve projected production and cash flows from operations from such wells could result in a reduction to our 2015 capital budget. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in natural gas prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facilities; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- our access to, and the cost of accessing, end markets for our production;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- our ability to borrow under our revolving credit facilities.

If our revenues or the borrowing base under our \$550.0 million Senior Secured Revolving Credit Facility decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our planned capital budget or our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our revolving credit facilities are 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 properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

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

Our future financial condition and results of operations will depend on the success of our development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas production or that we will not recover all or any portion of our investment in such wells or that various characteristics of the well will cause us to plug or abandon the well prior to producing in commercially viable quantities.

Our decisions to purchase, explore or develop prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of

our reserves.” In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

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- delays imposed by or resulting from compliance with regulatory requirements including limitations resulting from wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as blizzards and ice storms;
- issues related to compliance with environmental regulations;
 - environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for natural gas.

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

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

Our producing properties are geographically concentrated in the Appalachian Basin, with a particular concentration in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. As of December 31, 2014 and 2013, all of our total estimated proved reserves were attributable to properties located in these areas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other weather related conditions or interruption of the processing or transportation of oil, natural gas or NGLs and changes in regional and local political regimes and regulations. Such conditions could have a material adverse effect on our financial condition and results of operations. In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations. For example, third parties may engage in subsurface mining operations near or under our properties, which could cause subsidence or other damage to our properties, adversely impact our drilling or adversely impact our midstream activities or those on which we rely. In such event, our operations may be impaired or interrupted, and we may not be able to recover the costs incurred as a result of temporary shut-ins, the plugging and abandonment of any of our wells or the repair of our midstream facilities. Furthermore, the existence of mining operations near our properties could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. In connection with our acquisition of Alpha Holdings' 50% interest in our Marcellus joint venture on January 29, 2014, we agreed to continue to acknowledge the dominance of mining by Alpha Natural Resources, Inc. ("Alpha") within the area of mutual interest of our Marcellus joint venture. As such, in addition to coordinating with Alpha on, and in certain circumstances obtaining the prior approval of Alpha for, future drilling operations, we may also be required to take steps to assure the dominance of the mining operations of Alpha, including the plugging and abandonment of wells at the direction of Alpha upon two years notice. These restrictions on our operations, and any similar restrictions, can cause delays or interruptions or can prevent us from executing our business strategy, which could have a material adverse effect on our financial condition and results of operations.

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

We have been an early entrant into new or emerging plays. As a result, our initial drilling results in these areas may be less certain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We completed our first horizontal well in the Marcellus Shale in October 2010 and in the Utica Shale in June 2014.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are more developed and have a longer history of established production. Since new or emerging plays have limited or no production history we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Additionally, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. We cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

During the term of the Utica Development Agreements, we will rely on Gulfport for the success of our project in the Southern Contract Area in Belmont County, Ohio, and we may not be able to maximize the value of our properties in the Southern Contract Area as we deem best because we are not in full control of this project.

During the term of the Utica Development Agreements, the success of our operation in the Southern Contract Area in Belmont County, Ohio, will depend in part on the ability of Gulfport to effectively exploit the acreage it operates under the Development Agreement. Please read “Item 1. Business—Exploration and Production Business Segment—Development Agreement and Area of Mutual Interest Agreement.” Pursuant to the Development Agreement, we have designated Gulfport as the operator of our existing and future acreage in the Southern Contract Area. A failure or inability of Gulfport to adequately exploit the acreage it operates would have a significant impact on our results of operations. In addition, other than limitations set forth in the terms of the Development Agreement, we do not control the amount of capital that Gulfport may require for development of properties in the Southern Contract Area. Accordingly, we may be required to allocate capital to development of the Southern Contract Area at times when we otherwise would allocate capital to the Northern Contract Area, our Marcellus Shale acreage or elsewhere or otherwise be forced to terminate the Utica Development Agreements. Under any of these circumstances, our prospects for realization of the potential value of the oil, natural gas and NGL reserves associated with the Southern Contract Area could be adversely affected. Our lack of control may limit our ability to develop our properties in the manner we believe to be in our best interest.

Insufficient takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas prices.

The Appalachian Basin natural gas business environment has recently experienced periods in which production has surpassed local takeaway capacity, resulting in substantial discounts in the price received by producers such as us. Although additional Appalachian Basin takeaway capacity has been added in recent years, the existing and expected capacity may not be sufficient to keep pace with the increased production caused by accelerated drilling in the area in the short term. Furthermore, the costs associated with securing long-term firm transportation capacity has risen significantly on newer projects. There can be no assurance that the net impact of entering into such arrangements, after giving effect to their costs, will result in more favorable sales prices for our production in the future than local pricing. If we are unable to secure additional gathering and compression capacity and long-term firm takeaway capacity on major pipelines that are in existence or under construction in our core operating area to accommodate our growing production and to manage basis differentials, it could have a material adverse effect on our financial condition and results of operations.

We are required to pay fees to our service providers based on minimum volumes regardless of actual volume throughput.

We have various gas transportation service agreements in place, each with minimum volume delivery commitments. As of March 1, 2015, our average annual contractual firm transportation and firm sales obligations for 2015, 2016 and 2017 were approximately 813,000 MMBtu/d, 918,000 MMBtu/d and 1,011,000 MMBtu/d, respectively. While we believe that our future natural gas volumes will be sufficient to satisfy the minimum requirements under our gas transportation services agreements based on our current production and our exploration and development plan, we can provide no such assurances that such volumes will be sufficient. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput, which could be significant. If these fees on minimum volumes are substantial, we may not be able to generate sufficient cash to cover these obligations, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing.

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

Our revolving credit facility and the indenture (the “Indenture”) governing the \$900.0 million aggregate principal amount of 6.25% senior notes due 2022 (the “Senior Notes”) we issued in a private placement on April 25, 2014 (the “Senior Notes Offering”) contain a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness), including restrictive covenants that may limit our ability to, among other things:

- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- hedge future production or interest rates;
- incur liens;
- engage in certain other transactions without the prior consent of the lenders; and
- pay dividends.

In addition, our revolving credit facility and the Indenture require us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. On certain occasions in the past we have not met these financial covenants. These restrictions may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our revolving credit facility and under the Indenture impose on us.

Any significant reduction in our borrowing base under our Senior Secured Revolving Credit Facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations. Our Senior Secured Revolving Credit Facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid, or we must pledge other natural gas properties as additional collateral after applicable grace periods. As of December 31, 2014, we did not have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our revolving credit facility. As of October 2014, the borrowing base under our Senior Secured Revolving Credit Facility was \$550.0 million. The commodity prices used by our lenders in our most recent borrowing base determination were not reflective of the substantially lower commodity prices realized in December 2014 and January 2015. Our next scheduled borrowing base redetermination is expected to occur in April 2015.

A breach of any covenant in our revolving credit facility would result in a default under the facility after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the relevant facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements that include cross default provisions. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

In certain circumstances we may have to purchase commodities on the open market or make cash payments under our hedging arrangements and these payments could be significant.

If our production is less than the volume commitments under our hedging arrangements, or if natural gas or oil prices exceed the price at which we have hedged our commodities, we may be obligated to make cash payments to our hedge counterparties or purchase the volume difference at market prices, which could, in certain circumstances, be significant. As of December 31, 2014, we had entered into NYMEX hedging contracts through December 31, 2017

covering a total of approximately 202 Bcf of our projected natural gas production at a weighted average price of \$4.09 per MMBtu. We have also

entered into Appalachian hedging contracts through December 31, 2016 covering a total of approximately 45 Bcf of our projected natural gas production at a weighted average price of \$2.72 per MMBtu. If we have to purchase additional commodities on the open market or post cash collateral to meet our obligations under such arrangements, our cash otherwise available for use in our operations would be reduced.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The process of estimating natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

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

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

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. Please see “—The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.”

Reserve estimates for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. Less production history may contribute to less accurate estimates of reserves, future production rates and the timing of development expenditures. A substantial number of our producing wells have been operational for less than two years and estimated reserves vary substantially from well to well. Furthermore, the lack of operational history for horizontal wells in the Utica Shale may also contribute to the inaccuracy of future estimates of reserves and could result in our failing to achieve expected results in the play. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates would have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

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

As of December 31, 2014, we had 1,233 net drilling locations. As a result of the limitations described above, we may be unable to drill many of these locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful, may not increase our overall

proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our drilling locations, see “Item 2. Properties—Exploration and Production Segment—Reserve Data—Determination of Drilling Locations.” Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities. Leases on our oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2014, we had leases representing 2,905 undeveloped acres scheduled to expire in 2015, 5,694 undeveloped acres scheduled to expire in 2016, 31,988 undeveloped acres scheduled to expire in 2017, 35,498 undeveloped acres scheduled to expire in 2018 and 22,850 undeveloped acres set to expire in 2019 and thereafter. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Moreover, many of our leases require lessor consent to unitize, which may make it more difficult to hold our leases by production. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. Our reserves and future production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage and the loss of any leases could materially and adversely affect our ability to so develop such acreage.

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

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2014, 2013 and 2012, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas average prices without giving effect to derivative transactions. Accordingly, the natural gas price used in our reserve report as of December 31, 2014 was \$4.52 per Mcfe, which is not reflective of the substantially lower prices realized in December 2014 and January 2015. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production 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 and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. As a corporation, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent on our future taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report which could have a material effect on the value of our reserves.

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

Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due to the long history of land ownership in the area, resulting in extensive and complex chains of title. In the course of acquiring the rights to develop oil and natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment subject to title verification. In most cases, we incur the expense of retaining lawyers to verify the rightful owners of the oil and gas interests prior to payment of such lease bonus to the lessor. There is no certainty, however, that a lessor has valid title to its lease’s oil and gas interests. In those cases, such leases are generally voided and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of

such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and

reserves. Accordingly, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

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

As of December 31, 2014, approximately 51% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 662.4 Bcfe of estimated proved undeveloped reserves will require an estimated \$585.3 million of development capital over the next five years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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

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

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

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

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, we enter into derivative instrument contracts for a significant portion of our natural gas production, including fixed-price swaps. As of December 31, 2014, we had entered into NYMEX hedging contracts through December 31, 2017 covering a total of approximately 202 Bcf of our projected natural gas production at a weighted average price of \$4.09 per MMBtu. We have also entered into Appalachian hedging contracts through December 31, 2016 covering a total of approximately 45 Bcf of our projected natural gas production at a weighted average price of \$2.72 per MMBtu. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

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

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

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital

expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. As of December 31, 2014, the estimated fair value of our commodity derivative contracts was approximately \$196.2 million. Any default by the counterparties to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations.

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

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

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables (\$125.3 million at December 31, 2014) and the sale of our natural gas production to natural gas marketing companies (\$72.2 million in receivables as of December 31, 2014), including one natural gas marketing company which represented \$30.7 million in receivables at December 31, 2014. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with one natural gas marketing company. The largest purchaser of our natural gas during the year ended December 31, 2014 represented approximately 79% of our total sales. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

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

Substantial costs, liabilities, delays and other significant issues could arise from environmental laws and regulations inherent in drilling and well completion, gathering, transportation, and storage, and we may incur substantial costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, regional, state and local laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

• CAA, and analogous state law, which impose obligations related to air emissions;

• Clean Water Act ("CWA"), and analogous state law, which regulate discharge of wastewaters and storm water from some of our facilities into state and federal waters, including wetlands;

• CERCLA, and analogous state law, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;

• RCRA, and analogous state law, which impose requirements for the handling and discharge of any solid and hazardous waste from our facilities;

• NEPA, which requires federal agencies to study likely environmental impacts of a proposed federal action before it is approved, such as drilling on federal lands;

• SDWA, and analogous state law, which restrict the disposal, treatment or release of water produced or used during oil and gas development;

• ESA, and analogous state law, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species; and

• OPA of 1990, which requires oil storage facilities and vessels to submit to the federal government plans detailing how they will respond to large discharges, requires updates to technology and equipment, regulates above ground storage tanks and sets forth liability for spills by responsible parties.

Various governmental authorities, including, for example, the U.S. Environmental Protection Agency (the "EPA"), the U.S. Department of the Interior, the Bureau of Indian Affairs and analogous state agencies and tribal governments, have the

power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and/or criminal fines and penalties and liability for non-compliance, the imposition of remedial obligations, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions or declaratory relief limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases.

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

The EPA's National Enforcement Initiatives for 2014 to 2016, includes "Assuring Energy Extraction Sector Compliance with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us. We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, and any new capital costs may be incurred to comply with such changes. In addition, new environmental laws and regulations might adversely affect our products and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability. Further, new environmental laws and regulations might adversely affect our customers, which in turn could affect our profitability.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to the authority under the NGPSA and HLPESA, as amended by the Pipeline Safety Improvement Act, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the 2011 Pipeline Safety Act, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. These regulations

require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

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In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of pipeline integrity testing, but the results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the safe and reliable operation of our pipelines.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA or states that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking and sought public comment on a number of proposed changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 GAO report to Congress, the GAO acknowledged PHMSA’s assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPESA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from \$100,000 to \$200,000 per violation per day and also from \$1 million to \$2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. The SDWA regulates the underground injection of substances through the Underground Injection Control (“UIC”) program and exempts hydraulic fracturing from the definition of “underground injection”. Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as require disclosure of the chemical constituents of the fluids used in the fracturing process. The U.S. Congress may consider similar SDWA legislation in the future.

In addition, EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published final permitting guidance in February 2014 addressing the performance of such activities using diesel fuels in those states where EPA is the permitting authority. Also, in May 2014, the EPA issued an advanced notice of proposed rules under the Toxic Substances Control Act that would require companies to disclose information regarding the chemicals used in hydraulic fracturing. In addition, the U.S. Department of the Interior published a revised proposed rule on May 16, 2013, that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. Further, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, and a draft final report with conclusions about the potential impacts of hydraulic fracturing on drinking water resources is expected to be available for public comment and peer review sometime in the first half of 2015. Moreover, the EPA is developing effluent

limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards in 2015. And other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Along with several other states, Pennsylvania (where we conduct a majority of our operations) has adopted laws and proposed regulations that require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. The chemical ingredient information is generally available to the public via online databases, and this may bring more public scrutiny to hydraulic fracturing operations. In addition, local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. Although the Pennsylvania legislature passed legislation to make regulation of drilling uniform throughout the state, the Pennsylvania Supreme Court in *Robinson Township v. Commonwealth of Pennsylvania* struck down portions of that legislation. Following this decision, local governments in Pennsylvania may increasingly adopt ordinances relating to drilling and hydraulic fracturing activities, especially within residential areas. 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.

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

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

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

Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The CWA imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Specific to Pennsylvania, sending wastewater to POTWs requires certain levels of pretreatment that may effectively prohibit such disposal as a disposal option and our continued ability to use injection wells as a disposal option not only will depend on federal or state regulations but also on whether available injection wells have sufficient storage capacities. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

We are subject to risks associated with climate change.

There is a growing belief that emissions of GHGs may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks. In addition, legislative and regulatory responses related to GHGs and climate change creates the potential for financial risk. The U.S. Congress has previously considered legislation related to GHG

emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions. For example, the Obama administration recently announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas sector.

On September 22, 2009, the EPA finalized a GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent (CO₂e) emissions per year and to most upstream suppliers of fossil fuels, as well as manufacturers of vehicles and engines. Subsequently, on November 8, 2010, the EPA issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of CO₂e per year. The rule requires reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA each year in March under this rule. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency's reporting requirements to cover completions and workovers from hydraulically fractured oil wells. These changes to EPA's reporting rules could result in increased compliance costs.

The recent actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations.

Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

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

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

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

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

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

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

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

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

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

In the future we may make acquisitions of businesses that complement or expand our current business. However, we may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our credit facilities impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facilities also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

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

The successful acquisition of natural gas and oil properties requires an assessment of several factors, including:

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

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

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

Market conditions or the unavailability of satisfactory natural gas, NGL or oil transportation arrangements may hinder our access to markets or delay our production. The availability of a ready market for our production depends on a number of factors, including the demand for and supply of natural gas, NGLs or oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGL or oil pipeline or gathering system capacity. In addition, if quality specifications for the third-party pipelines with which we connect change so as to restrict our ability to transport product, our access to markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our exploration and production and midstream operations are subject to complex and stringent federal, state and local laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations and the permits and other approvals issued thereunder. In addition, our costs of compliance may increase or operational delays may occur if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations. Also, we might not be able to obtain or maintain all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs.

In addition, new or additional regulations or permitting requirements, new interpretations of requirements or changes in our operations could also trigger the need for Environmental Assessments or more detailed Environmental Impact Statements under NEPA and analogous state laws, as well as litigation over the adequacy of those reviews, which could result in increased costs or delays of, or denial of rights to conduct, our development programs.

Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows. Further, the discharges of oil, natural gas, NGLs and other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties. See “Item 1. Business—Regulation of Environmental and Occupational Safety and Health Matters” for a further description of laws and regulations that affect us.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis. The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA, exempts natural gas gathering facilities from regulation by the FERC, as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company.

However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation, the rates for, and terms and conditions of services provided by such facility would be subject to regulation by the FERC. Such regulation could decrease revenues, increase operating costs, and depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by the FERC.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. We cannot predict what new or different regulations federal and state regulatory agencies may adopt, or what effect subsequent regulation may have on our activities. Such regulations may have a material adverse effect on our financial condition, result of operations and cash flows.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, or (“EPAct 2005”), FERC has civil penalty authority under the NGA to impose penalties for current violations of up to \$1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas company under the NGA, we are required to report aggregate volumes of natural gas purchased or sold at wholesale to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. In addition, Congress may enact legislation or FERC may adopt regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to further

regulation. Failure to comply with those regulations in the future could subject us to civil penalty liability.

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for

investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations. We are susceptible to the potential difficulties associated with rapid growth and expansion.

We have grown rapidly over the last several years and more than doubled our employee workforce since 2013. Our management believes that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties.

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

Natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect various wildlife. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Increases in interest rates could adversely affect our business.

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

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (“CFTC”) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized some regulations, including critical rulemakings on the definition of “swap,” “swap dealer,” and “major swap participant”, others remain to be finalized and it is not possible at this time to predict when this will be accomplished.

The Dodd-Frank Act authorized the CFTC to establish rules and regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The CFTC’s initial position limits rules were vacated by the U.S. District Court for the District of Columbia in September 2012.

However, on November 5,

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2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

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

The Dodd-Frank Act and regulations may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

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

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

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

The Fiscal Year 2015 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 that would implement many of these proposals. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In February 2012, the state legislature of Pennsylvania passed a new natural gas impact fee in Pennsylvania. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. The fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices from the last day of each month. There can be no assurance that the impact fee will remain as currently structured or that new or additional taxes will not be imposed. In addition, there is currently no severance tax imposed on natural gas or oil in Pennsylvania. However, it is possible that a severance tax could be proposed and implemented in the coming years, which would negatively affect our future cash flows and financial condition.

In February 2013, the governor of the state of Ohio proposed a plan to enact new severance taxes in fiscal 2014 and 2015. However, the Ohio State Senate did not include a severance tax increase in the version of the budget bill that it passed on June 7, 2013. The possibility remains that the severance tax increase on horizontal wells will resurface during compromise talks on the budget.

Risks Related to Our Common Stock

If we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our

financial results could be adversely affected.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. Prior to the completion of our IPO, we were a private company with limited accounting personnel to adequately execute our accounting processes and other supervisory resources with which to address our internal control over financial reporting. In addition, our Marcellus joint venture historically relied on our accounting personnel for its accounting processes. We and our Marcellus joint venture had not maintained effective control environments in that the design and execution of our controls had not consistently resulted in effective review and supervision by individuals with financial reporting oversight roles. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare the financial statements of us and our Marcellus joint venture. We concluded that these control deficiencies constituted a material weakness in our control environment and in the control environment of our Marcellus joint venture as of December 31, 2012 and December 31, 2013.

To address these control deficiencies, we hired additional accounting and financial reporting staff, implemented additional analysis and reconciliation procedures and increased the levels of review and approval. Additionally, we comprehensively documented and analyzed our system of internal control over financial reporting in preparation for our first management report on internal control over financial reporting required in connection with this Annual Report. We have concluded that the material weakness previously identified had been remediated as of December 31, 2014. Furthermore, while we generally had to comply with Section 404 of the Sarbanes Oxley Act of 2002 for our fiscal year ended December 31, 2014, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an “emerging growth company” within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our annual report for the fiscal year ending December 31, 2019.

We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our shares of common stock. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our shares of common stock. Rice Holdings, the Rice Energy Irrevocable Trust and NGP Holdings collectively hold a substantial portion of our common stock.

Rice Holdings, Rice Energy Irrevocable Trust, NGP Holdings and Alpha Holdings collectively held approximately 48.8% of our common stock according to the Schedule 13D/A filed on January 14, 2015. So long as Rice Holdings, the Rice Energy Irrevocable Trust and NGP Holdings continue to control a significant amount of our common stock, each will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. The existence of significant stockholders may also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. In any of these matters, the interests of Rice Holdings, the Rice Energy Irrevocable Trust and NGP Holdings may differ or conflict with the interests of our other stockholders. Moreover, this

concentration of stock ownership may also adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder.

Conflicts of interest could arise in the future between us and one or more of our sponsors concerning among other things, potential competitive business activities or business opportunities. Any actual or perceived conflicts of interest could have an adverse impact on the trading price of our common stock.

Our sponsors include other participants in the energy industry, including Natural Gas Partners and affiliates of the family of Daniel J. Rice III (the Lead Portfolio Manager in the energy division at GRT Capital Partners). Certain of our sponsors and/

or their affiliates make investments in the U.S. oil and gas industry from time to time. As a result, our sponsors and/or their affiliates may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. In certain circumstances, they may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Under our certificate of incorporation, certain of our sponsors and/or one or more of their respective affiliates are permitted to engage in business activities or invest in or acquire businesses which may compete with our business or do business with any client of ours.

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

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

- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our bylaws; and
- establishing advance notice and certain information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

We do not intend to pay dividends on our common stock, and our Senior Secured Revolving Credit Facility and the Indenture place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, our Senior Secured Revolving Credit Facility and our Indenture place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it, or which there is no guarantee.

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

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities.

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

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

In April 2012, President Obama signed into law the JOBS Act. We are classified as an “emerging growth company” under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act, (2) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) provide certain disclosure regarding executive compensation required of larger public companies or (4) hold nonbinding advisory

votes on executive compensation. We will remain an emerging growth

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company for up to five years, although we will lose that status sooner if we have more than \$1.0 billion of revenues in a fiscal year, become a large accelerated filer, or issue more than \$1.0 billion of non-convertible debt over a three-year period.

After we are no longer an “emerging growth company,” we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not emerging growth companies.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock. Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

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

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

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Property Overview

Our properties are primarily located in Washington and Greene Counties, Pennsylvania, and Belmont County, Ohio. The following illustrations depict the acreage position of our Exploration and Production segment and the midstream assets of our Midstream segment, each as of December 31, 2014.

The majority of our properties are located on or under on or under private properties owned in fee, held by lease or occupied under perpetual easements or other rights acquired without warranty of underlying land titles.

Exploration and Production Segment Properties

All of the current and planned operations of our Exploration and Production segment are located in what we believe to be the core of the Marcellus Shale in southwestern Pennsylvania and of the Utica Shale in eastern Ohio, each of which are located in the Appalachian Basin. In addition, we have operations in the Upper Devonian Shale on our Pennsylvania acreage. The properties of our Exploration and Production segment consist of interests in developed and undeveloped leases that entitle us to drill for and produce natural gas, NGLs and crude oil. Our interests are mostly in the form of working interests and, to a lesser extent, royalty and overriding royalty interests.

The table below summarizes data for our exploration and production operations for the year ended December 31, 2014.

Region	Average Daily Net Production (MMcfe/d)	Production (MMcfe)	Percentage of Production	Proved Reserves (MMcfe)	Percentage of Proved Reserves
Marcellus Shale (1)	245	89,607	92	% 1,207,000	92 %
Utica Shale	19	6,926	7	% 91,463	7 %
Upper Devonian Shale	3	1,204	1	% 8,108	1 %
	267	97,737	100	% 1,306,571	100 %

(1) Marcellus shale production for the years ended December 31, 2013 and December 31, 2012 was 22,995 MMcfe and 8,769 MMcfe, respectively.

Reserve Data

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the U.S. Securities and Exchange Commission (“SEC”).

Reserves Presentation

Our estimated proved reserves and PV-10 as of December 31, 2014, 2013 and 2012 are based on evaluations prepared by our independent reserve engineers, NSAI. Copies of the summary reports of NSAI with respect to our reserves as of December 31, 2014 are filed as exhibits to this Annual Report. See “—Preparation of Reserve Estimates” for definitions of proved reserves and the technologies and economic data used in their estimation.

The following table summarizes our historical estimated proved reserves and related PV-10 at December 31, 2014, 2013 and 2012.

	Estimated Net Reserves (Bcfe) ^{(1) (2)}		
	December 31 2014	2013	2012
Estimated Proved Reserves:			
Total proved reserves	1,307	382	304
Total proved developed reserves	645	144	61
Total proved developed producing reserves	569	91	57
Total proved developed non-producing reserves	76	53	4
Total proved undeveloped reserves	662	238	243
Percent proved developed	49	% 38	% 20 %
PV-10 of proved reserves (in millions) ⁽³⁾	\$1,744	\$417	\$102

(1) Our historical estimated proved reserves, PV-10 and standardized measure were determined using a 12-month average price for natural gas. The prices used in our reserve report yield weighted average wellhead prices, which are based on index prices and adjusted for energy content, transportation fees and regional price differentials. The index prices and the equivalent wellhead prices are shown in the table below.

Index Prices	December 31 ⁽ⁱ⁾		
	2014	2013	2012
Natural Gas (per MMBtu) ⁽ⁱⁱ⁾	\$4.35	\$3.67	\$2.76
Oil (per Bbl)	91.48	—	—
Weighted Average Wellhead Prices			
Natural Gas (per Mcfe) ⁽ⁱⁱⁱ⁾	\$4.52	\$3.91	\$2.86
Oil (per Bbl)	85.70	—	—

Amounts presented in the table exclude amounts attributable to our Marcellus joint venture for periods prior to the (i) completion of our IPO in January 2014. In connection with our IPO, we acquired the remaining 50% interest in our Marcellus joint venture from our j

oint venture partner, and as such amounts shown as of December 31, 2014 include 100% of the amounts attributable to our Marcellus joint venture.

(ii) Index prices of our natural gas per MMBtu were \$3.67 and \$2.76 for our 50% equity investment in our Marcellus joint venture for the years ended December 31, 2013 and 2012, respectively.

(iii) Weighted average wellhead prices of our natural gas per Mcfe were \$3.90 and \$2.84 for our 50% equity investment in our Marcellus joint venture for the years ended December 31, 2013 and 2012, respectively.

Amounts presented in the table exclude amounts attributable to our Marcellus joint venture for periods prior to the completion of our IPO in January 2014. In connection with our IPO, we acquired the remaining 50% interest in our Marcellus joint venture from our joint venture partner, and as such amounts shown as of December 31, 2014 include 100% of the amounts attributable to our Marcellus joint venture. The table below summarizes historical estimated proved reserves and related PV-10 at December 31, 2013 and 2012 for our 50% interest in the Marcellus joint venture:

	Estimated Net Reserves (Bcfe)	
	December 31	
	2013	2012
Estimated Proved Reserves:		
Total proved reserves	110	128
Total proved developed reserves	53	35
Total proved developed producing reserves	43	22
Total proved developed non-producing reserves	10	13
Total proved undeveloped reserves	57	93
Percent proved developed	48	% 27
PV-10 of proved reserves (in millions) ⁽³⁾	\$146	\$71

PV-10 is a non-GAAP financial measure and generally differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Our pre-tax PV-10 at December 31, 2014 was \$1.7 billion. We estimate that our historical standardized measure as of December 31, 2014, is approximately \$1.3 billion as adjusted to give effect to the present value of approximately \$436 million of future income taxes. However, the historical PV-10s and standardized measures of us and our Marcellus joint venture were equivalent, as of December 31, 2013 and 2012, because our accounting predecessor, Rice Drilling B, and our Marcellus joint venture were not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes provided for such periods because taxable income was passed through to Rice Drilling B's and our Marcellus joint venture's respective equity holders. However, in connection with the closing of our IPO, as a result of our corporate reorganization, Rice Energy Inc. became the sole member of Rice Drilling B. Rice Energy Inc. is a corporation subject to federal income tax and, as such, our future income taxes are dependent upon our future taxable income. We estimate that our historical standardized measure and the historical standardized measure for our Marcellus joint venture as of December 31, 2013, would have been approximately \$269 million and \$175 million, respectively, as adjusted to give effect to the present value of approximately \$148 million and \$117 million, respectively, of future income taxes as a result of our being treated as a corporation for federal income tax purposes. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in the estimated historical proved undeveloped reserves of us during 2014, 2013 and 2012 (in MMcfe):

	Rice Energy Inc. ⁽¹⁾	
Proved undeveloped reserves, December 31, 2011	207,599	
Conversions into proved developed reserves	(15,120)
Extensions	164,561	
Price and performance revisions	(113,993)
Proved undeveloped reserves, December 31, 2012	243,047	
Conversions into proved developed reserves	(79,266)
Extensions	65,744	
Price and performance revisions	8,826	
Proved undeveloped reserves, December 31, 2013	238,351	
Acquisitions	122,466	
Conversions into proved developed reserves	(97,858)
Extensions	417,604	
Price and performance revisions	(18,141)
Proved undeveloped reserves, December 31, 2014	662,422	

Amounts presented in the table above exclude amounts attributable to our Marcellus joint venture for periods prior to the completion of our IPO in January 2014. In connection with our IPO, we acquired the remaining 50% interest in our Marcellus joint venture from our joint venture partner, and as such the acquisition is reflected in the table above. The proved undeveloped reserves balance as of December 31, 2014, includes 100% of the amounts attributable to our Marcellus joint venture. The table below summarizes the changes in the estimated historical proved undeveloped reserves during 2013 and 2012 for our 50% interest in the Marcellus joint venture:

	Marcellus Joint Venture	
Proved undeveloped reserves, December 31, 2011	43,629	
Conversions into proved developed reserves	(9,394)
Extensions	83,145	
Price and performance revisions	(24,275)
Proved undeveloped reserves, December 31, 2012	93,105	
Conversions into proved developed reserves	(38,435)
Extensions	19,811	
Price and performance revisions	(17,168)
Proved undeveloped reserves, December 31, 2013	57,313	

During 2014, extensions, discoveries, and other additions of 417,604 MMcfe of proved undeveloped reserves were added through the drillbit in the Marcellus Shale. We incurred cumulative costs of approximately \$88.1 million, of which \$63.4 million was incurred in 2014, to convert 97,858 MMcfe of proved undeveloped reserves to proved developed reserves in 2014. Estimated future development costs relating to the development of our proved undeveloped reserves as of December 31, 2014 are approximately \$585.3 million over the next five years, which we expect to finance through cash flow from operations, borrowings under our Senior Secured Revolving Credit Facility and other sources of capital financing. Our drilling programs are focused on proving our undeveloped leasehold acreage through delineation drilling. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also focus on drilling our proved undeveloped reserves. Based on our reserve report as of December 31, 2014, we had 62 net drilling locations in the Marcellus Shale associated with proved undeveloped reserves and 10 net drilling locations in the Marcellus Shale associated with proved developed not producing reserves, and we had four net drilling locations in the Utica Shale associated with proved undeveloped reserves and one net drilling location in the Utica Shale associated with proved developed not producing reserves. All of our proved undeveloped reserves are expected to be developed within five years of their initial booking date. See

“Item 1A. Risk Factors—Risks Related to Our Business—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.”

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2014, 2013 and 2012 included in this Annual Report were based on evaluations prepared by the independent petroleum engineering firm of NSAI in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources.

Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. The technical and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, well-test data, production data (including flow rates), well data (including lateral lengths), historical price and cost information, and property ownership interests. Our independent reserve engineers use this technical data, together with standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis and analogy. The proved developed reserves and EURs per well are estimated using performance analysis and volumetric analysis. The estimates of the proved developed reserves and EURs for each developed well are used to estimate the proved undeveloped reserves for each proved undeveloped location (utilizing type curves, statistical analysis, and analogy). Proved undeveloped locations that are more than one offset from a proved developed well utilized reliable technologies to confirm reasonable certainty. The reliable technologies that were utilized in estimating these reserves include log data, performance data, log cross sections, seismic data, core data, and statistical analysis.

Internal Controls

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserves estimation process. Ryan I. Kanto, our Vice President of Asset Performance, is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has substantial industry experience with positions of increasing responsibility in engineering and evaluations. Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the reserve report is reviewed by our senior management with representatives of our independent reserve engineers and internal technical staff.

Qualifications of Responsible Technical Persons

Ryan I. Kanto joined Rice Energy in June 2011 and serves as our Vice President of Asset Performance. Prior to Rice Energy, Mr. Kanto worked at EnCana Oil & Gas (USA) Inc. from June 2007 to May 2011. During this time he served as a facilities engineer in the Deep Bossier from June 2007 to January 2008, a reservoir engineer in the Barnett Shale until February 2009, and completion engineer in the Haynesville Shale until his departure. Mr. Kanto has bachelors degrees in Chemical Engineering and Engineering Management from the University of Arizona and has significant experience in unconventional shale gas plays.

Our proved reserve estimates shown herein at December 31, 2014, 2013 and 2012 and the proved reserve estimates shown herein for our Marcellus joint venture have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under the Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI letters, each of which is filed as an exhibit to this Annual Report, was Steven W. Jansen and David E. Nice. Mr. Jansen, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over four years of prior industry experience. Mr. Nice, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since

1998 and has over 13 years of prior industry experience. Messrs. Jansen and Nice meet or exceed the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; they are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Determination of Drilling Locations

Net undeveloped locations are calculated by taking our total net acreage and multiplying such amount by a risking factor which is then divided by our expected well spacing. We then subtract net producing wells to arrive at undeveloped net drilling locations.

Undeveloped Net Marcellus Locations – We assume these locations have 7,000 foot laterals and 750 foot spacing between wells which yields approximately 121 acre spacing. In the Marcellus, we apply a 20% risking factor to our net acreage to account for inefficient unitization and the risk associated with our inability to force pool in Pennsylvania. As of December 31, 2014, we had approximately 64,000 net acres in the Marcellus which results in 356 undeveloped net locations.

Undeveloped Net Greene County Locations – We assume these locations have 7,000 foot laterals and 750 foot spacing between wells which yields approximately 121 acre spacing. In Greene County, we apply a 20% risking factor to our net acreage to account for inefficient unitization and the risk associated with our inability to force pool in Pennsylvania. As of December 31, 2014, we had approximately 22,000 net acres in Greene County which results in 139 undeveloped net locations.

Undeveloped Net Upper Devonian Locations - We assume these locations have 7,000 foot laterals and 1,000 foot spacing between wells which yields approximately 161 acre spacing. In the Upper Devonian, we apply a 20% risking factor to our net acreage to account for inefficient unitization and the risk associated with our inability to force pool in Pennsylvania. As of December 31, 2014, we had approximately 77,000 net acres prospective for the Upper Devonian which results in 382 undeveloped net locations.

Undeveloped Net Utica Locations - We assume these locations have 8,000 foot laterals and 750 foot spacing between wells which yields approximately 138 acre spacing. In the Utica, we apply a 10% risking factor to our net acreage to account for inefficient unitization. As of December 31, 2014, we had approximately 55,000 net acres prospective for the Utica in Ohio which results in 356 undeveloped net locations.

Production, Revenues and Price History

Natural gas, NGLs, and oil are commodities; therefore, the price that we receive for our production is largely a function of market supply and demand. While demand for natural gas in the United States has increased dramatically since 2000, natural gas and NGL supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have been used to find and recover large amounts of oil and natural gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas can result in substantial price volatility.

Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas reserves that may be economically produced and our ability to access capital markets. See “Item 1A. Risk Factors—Risks Related to Our Business—Natural gas, NGL and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.”

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The following table sets forth information regarding production, revenues and realized prices and production costs on a historical basis for the years ended December 31, 2014, 2013 and 2012.

	For the Year Ended December 31, ⁽¹⁾		
	2014	2013	2012
Natural gas sales (in thousands)	\$354,860	\$87,847	\$26,743
Oil and NGL sales (in thousands)	4,341	—	—
Natural gas, oil and NGL sales (in thousands)	\$359,201	\$87,847	\$26,743
Natural gas production (MMcf)	97,172	22,995	8,769
Oil and NGL production (MBbls)	94	—	—
Total production (MMcfe)	97,737	22,995	8,769
Average prices before effects of hedges per Mcf	\$3.65	\$3.82	\$3.05
Average realized prices after effects of hedges per Mcf ⁽²⁾	3.46	3.85	3.15
Average oil and NGL prices per Bbl	46.07	—	—
Average costs per Mcfe ⁽³⁾			
Lease operating	\$0.26	\$0.36	\$0.42
Gathering, compression and transportation	0.38	0.43	0.43
Production taxes and impact fees	0.05	0.07	0.16
General and administrative	0.43	0.74	0.87
Depletion, depreciation and amortization	1.55	1.43	1.61

Amounts presented in the table above exclude amounts attributable to our Marcellus joint venture for periods prior to the completion of our IPO in January 2014. In connection with our IPO, we acquired the remaining 50% interest in our Marcellus joint venture from our joint venture partner, and as such amounts shown for the year ended December 31, 2014 include 100% of the amounts attributable to our Marcellus joint venture from the date of (1) acquisition forward and amounts for the years ended December 31, 2013 and 2012 do not include amounts attributable to our Marcellus joint venture. The table below sets forth information regarding production, revenues and realized prices and production costs (excluding the impact of production taxes and impact fees) on a historical basis for the years ended December 31, 2013 and 2012 for our 50% equity investment in our Marcellus joint venture:

	For the Year Ended December 31,	
	2013	2012
Natural gas sales (in thousands)	\$45,339	\$13,142
Natural gas production (MMcf)	11,443	4,296
Average prices before effects of hedges per Mcf	\$3.96	\$3.06
Average realized prices after effects of hedges per Mcf ⁽²⁾	4.16	3.07
Average costs per Mcfe		
Lease operating	\$0.36	\$0.39
Gathering, compression and transportation	0.68	0.78
General and administrative	0.14	0.24
Depletion, depreciation and amortization	1.09	1.10

(2) The effect of hedges includes realized gains and losses on commodity derivative transactions.

(3) Average costs per Mcfe for the year ended December 31, 2014 as presented reflects cost attributable to our Exploration and Production segment. On a consolidated basis, the applicable costs per Mcfe are as follows: lease operating - \$0.26; gathering, compression and transportation - \$0.41; production taxes and impact fees - \$0.05;

general and administrative - \$0.57; and depletion, depreciation and amortization - \$1.60.

Productive Wells

As of December 31, 2014, we had a total of 85 gross (78 net) producing wells in the Marcellus Shale, a total of three net producing wells in the Upper Devonian Shale, and a total of 23 gross (7 net) producing wells in the Utica Shale.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2014. Approximately 47% of our Marcellus acreage and 2% of our Utica acreage was held by production at December 31, 2014. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

Basin	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Marcellus	10,897	9,955	77,290	75,554	88,187	85,509
Utica	4,870	1,256	55,695	53,804	60,565	55,060
Total	15,767	11,211	132,985	129,358	148,752	140,569

Undeveloped Acreage Expirations

The following table sets forth the number of total undeveloped acres as of December 31, 2014 that will expire in 2015, 2016, 2017, 2018 and 2019 and thereafter unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed. We have not attributed any PUD reserves to acreage for which the expiration date precedes the scheduled date for PUD drilling. In addition, we do not anticipate material delay rental or lease extension payments in connection with such acreage.

Basin	2015	2016	2017	2018	2019+
Marcellus	2,905	5,368	3,897	16,005	17,016
Utica	—	326	28,091	19,493	5,834
Total	2,905	5,694	31,988	35,498	22,850

Operated Drilling Activity

The following table describes our drilling activity on our acreage during the years ended December 31, 2014, 2013 and 2012:

	Productive Wells		Dry Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
2014	44.0	38.6	—	—	44.0	38.6
2013	23.0	20.9	—	—	23.0	20.9
2012	10.0	10.0	—	—	10.0	10.0

We drilled four exploratory wells during 2014 and one exploratory well in 2013. We did not drill any exploratory wells during 2012.

Title to Properties

In the course of acquiring the rights to develop oil and natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment subject to title verification. In most cases, we incur the expense of retaining lawyers to verify the rightful owners of the oil and gas interests prior to payment of such lease bonus to the lessor. There is no certainty, however, that a lessor has valid title to its lease's oil and gas interests. In those cases, such leases are generally voided and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under natural gas leases; or
- net profits interests.

Midstream Segment Properties

The gathering, compression and fresh water distribution systems of our Midstream segment are located in what we believe to be the core of the Marcellus Shale in southwestern Pennsylvania and of the Utica Shale in eastern Ohio, each of which are located in the Appalachian Basin. As of December 31, 2014, the RMP owned our gas gathering systems in each of Washington and Greene Counties, Pennsylvania, and we owned our gathering system in Belmont County, Ohio and our fresh water distribution systems in Washington and Greene Counties, Pennsylvania, and Belmont County, Ohio.

RMP's Pennsylvania Gathering Systems

RMP has secured dedications from us under a 15 year, fixed-fee contract for gathering and compression services covering (i) approximately 65,000 gross acres of our acreage position as of December 31, 2014 in Washington and Greene Counties, Pennsylvania, and (ii) any future acreage we acquire within these counties, other than in select areas subject to pre-existing third-party dedications and subject to the terms of contract. In addition, RMP has secured dedications from third-party customers under fixed-fee contracts for gathering and compression services in Washington County, Pennsylvania with respect to approximately 21,000 of their existing gross acres, and any future acreage they may acquire within areas of mutual interest of approximately 66,000 acres.

Washington County System

As of December 31, 2014, our Washington County gathering system consists of a network of 71 miles of 6- to 30-inch gathering pipelines and 7,320 horsepower of compression used to compress natural gas for our Exploration and Production segment and third-party producers. As of December 31, 2014, this system was connected to all of our 48 horizontal Marcellus producing wells in Washington County.

We began constructing the Washington County gathering system in January 2010, in connection with commencing horizontal development of our Marcellus Shale acreage. As of December 31, 2014, our Washington County gathering system has approximately 2.8 MMDth/d of gathering capacity with connections to Dominion, TCO, EQT and TETCO. During 2015, we expect to complete construction of the Washington County gathering system with the addition of approximately 21 miles of high pressure pipeline in central Washington County. Upon completion of construction, we expect that the Washington County gathering system will have approximately 3.3 MMDth/d of capacity.

Greene County System

As of December 31, 2014, our Greene County gathering system consists of a network of 10 miles of 6- to 16-inch gathering pipelines that collects natural gas from us and has a capacity of approximately 420 MDth/d. In addition, as of December 31, 2014, this system was connected to 30 horizontal Marcellus producing wells in Greene County, excluding wells acquired with the Greene County acreage acquisition. During 2015, we expect to expand the Greene County gathering system by constructing an additional 9 miles of high pressure pipeline that will result in aggregate capacity of approximately 840 MDth/d upon completion of construction.

Our Ohio Gathering System

We are constructing an aggregate of 50 miles of high-pressure gas gathering pipeline with capacity of 2.6 MMDth/d in the core of the Utica Shale in Belmont County, Ohio. Average daily throughput on our Ohio gathering system for January 2015 was 100 MDth/d. We expect this system will be substantially completed in mid to late 2015 and will service approximately 37,000 and 20,000 net acres of our current position and Gulfport's current position, respectively, in Belmont County, Ohio. In July 2014, we entered into a letter of intent with Gulfport pursuant to which Gulfport is expected to dedicate its production from the aforementioned acreage. Also in July 2014, we entered into a letter of intent with MarkWest Energy Partners, LP, or MarkWest, pursuant to which MarkWest will construct gas gathering facilities to gather our Utica Shale production from certain dedicated areas in Ohio, including portions of Belmont County, which production we anticipate will be wet gas and therefore will require processing. Both of these letters of intent are non-binding and the execution of definitive agreements with respect thereto is subject to, among other things, the ability of the applicable parties to reach agreement on commercial and other business terms.

Our Fresh Water Distribution Systems

As of December 31, 2014, each of our fresh water distribution systems in Washington and Greene Counties, Pennsylvania, and Belmont County, Ohio are under various stages of construction and are expected to be completed in mid to late 2015.

Pennsylvania Water Systems. We are expanding two independent fresh water distribution systems that, upon completion, will have direct access to 9.2 MMGPD of fresh water from the Monongahela River and several other regional water sources for distribution to our Exploration and Production segment's well completion operations in the Marcellus Shale.

Ohio Water System. We are constructing a fresh water distribution system that, upon completion, will have direct access to 16.7 MMGPD of fresh water from the Ohio River and several other regional sources for distribution to our Exploration and Production segment's well completion operations.

These systems consist of a combination of permanent buried pipelines, portable surface pipelines and fresh water impoundments, as well as pumping stations to transport the fresh water throughout the pipeline system. Because hydraulic fracturing requires substantial volumes of fresh water, these fresh water distribution services are utilized in connection with completion activities.

Title to Properties

The real property tied to our midstream operations is classified into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our pipelines and major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our pipelines and major facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. We have leased or owned these lands without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership of such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

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

Market Information. Our common stock is listed on the NYSE under the symbol “RICE.” Our common stock began trading on the NYSE on January 24, 2014. The high and low sales prices reflected on the NYSE per share for 2014 are summarized below:

(in U.S. dollars per share)	2014	
	High	Low
1st Quarter	\$28.07	\$20.78
2nd Quarter	34.34	25.80
3rd Quarter	30.57	25.02
4th Quarter	30.10	20.73

On March 10, 2015, the last sales price of our common stock, as reported on the NYSE, was \$17.91 per share.

Holders. The number of shareholders of record of our common stock was approximately 31 as of March 10, 2014. The number of registered holders does not include holders that have shares of common stock held for them in “street name,” meaning that the shares are held for their accounts by a broker or other nominee. In these instances, the brokers or other nominees are included in the number of registered holders, but the underlying holders of the common stock that have shares held in “street name” are not.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our Senior Secured Revolving Credit Facility and the Indenture restrict the payment of cash dividends on our common stock. We intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Securities Authorized for Issuance under 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 Sales of Securities. On January 29, 2014, pursuant to the Master Reorganization Agreement among us, Rice Drilling B, Rice Appalachia, Rice Holdings, Rice Partners, NGP Holdings, affiliates of Natural Gas Partners, Mr. Daniel J. Rice III, Rice Merger LLC (“Merger Sub”) and each of the persons holding incentive units representing interests in Rice Appalachia (collectively, the “Incentive Unitholders”) dated as of January 23, 2014, (i) (a) Rice Partners contributed a portion of its interests in Rice Appalachia to Rice Holdings, (b) Natural Gas Partners contributed its interests in Rice Appalachia to NGP Holdings and (c) the Incentive Unitholders contributed a portion of their incentive units to Rice Holdings and NGP Holdings, each in return for substantially similar incentive units in such entities; (ii) NGP Holdings, Rice Holdings and Mr. Daniel J. Rice III contributed their respective interests in Rice Appalachia to us in exchange for 43,452,550, 20,300,923 and 2,356,844 shares of our common stock, respectively; (iii) Rice Partners contributed its remaining interest in Rice Appalachia to us in exchange for 20,000,000 shares of our common stock; (iv) the Incentive Unitholders contributed their remaining interests in Rice Appalachia to us in exchange for 160,831 shares of our common stock, each of which were issued by us in connection with the closing of our IPO.

In addition, on January 29, 2014, pursuant to the Agreement and Plan of Merger among us, Rice Drilling B and Merger Sub dated as of January 23, 2014, we issued 1,728,852 shares of our common stock to the members of Rice Drilling B (other than Rice Appalachia).

The foregoing transactions were undertaken in reliance upon an exemption from the registration requirements of the Securities Act by Section 4(a)(2) thereof.

Issuer Purchases of Equity Securities. Neither we nor any “affiliated purchaser” repurchased any of our equity securities in the year ended December 31, 2014.

Item 6. Selected Financial Data

Set forth below is our selected historical consolidated financial data as of and for the years ended December 31, 2014, 2013 and 2012. The selected historical consolidated financial data set forth below is not intended to replace our historical consolidated financial statements. You should read the following data along with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and related notes, each of which is included in this report. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

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(in thousands, except share data)	Year Ended December 31,		
	2014	2013	2012
Operating revenues:			
Natural gas, oil and natural gas liquids (NGL) sales	\$359,201	\$87,847	\$26,743
Firm transportation sales, net	26,237	—	—
Other revenue	5,504	840	457
Total operating revenues	390,942	88,687	27,200
Operating expenses:			
Lease operating	24,971	8,309	3,688
Gathering, compression and transportation	40,225	9,774	3,754
Production taxes and impact fees	4,647	1,629	1,382
Exploration	4,225	9,951	3,275
Incentive unit expense	105,961	—	—
Restricted unit expense	—	32,906	—
Stock compensation expense	5,553	—	—
General and administrative	56,017	16,953	7,599
Depreciation, depletion and amortization	156,270	32,815	14,149
Acquisition expense	2,339	—	—
Amortization of intangible assets	1,156	—	—
Write-down of abandoned leases	—	—	2,253
Loss from sale of interest in gas properties	—	4,230	—
Total operating expenses	401,364	116,567	36,100
Operating loss	(10,422) (27,880) (8,900
Interest expense	(50,191) (17,915) (3,487
Gain on purchase of Marcellus joint venture	203,579	—	—
Other income (loss)	893	(440) 112
Gain (loss) on derivative instruments	186,477	6,891	(1,381
Amortization of deferred financing costs	(2,495) (5,230) (7,220
Loss on extinguishment of debt	(7,654) (10,622) —
Write-off of deferred financing costs	(6,896) —	—
Equity in income (loss) of joint ventures	(2,656) 19,420	1,532
Income (loss) before income taxes	310,635	(35,776) (19,344
Income tax expense	(91,600) —	—
Net income (loss)	219,035	(35,776) (19,344
Less: Net income attributable to noncontrolling interests	(581) —	—
Net income (loss) attributable to Rice Energy Inc.	\$218,454	\$(35,776) \$(19,344
Weighted average number of shares of common stock - basic	128,151,171	80,441,905	58,231,763
Weighted average number of shares of common stock - diluted	128,225,155	80,441,905	58,231,763
Earnings (loss) per share—basic	\$1.70	\$(0.44) \$(0.33
Earnings (loss) per share—diluted	\$1.70	\$(0.44) \$(0.33
Balance sheet data (at period end):			
Cash	\$256,130	\$31,612	\$8,547
Total property and equipment, net	2,461,331	734,331	273,640
Total assets	3,527,949	879,810	344,971
Total debt	900,680	426,942	149,321
Total equity before noncontrolling interest	1,522,710	298,647	138,191

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Net cash provided by (used in):				
Operating activities	\$85,075	\$33,672	\$(3,014)
Investing activities	(1,481,465) (458,595) (119,973)
Financing activities	1,620,908	447,988	127,145	
Other financial data (Unaudited):				
Adjusted EBITDAX	\$246,610	\$52,258	\$11,768	

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Non-GAAP Financial Measures

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDAX as net income (loss) before interest expense; depreciation, depletion and amortization; amortization of deferred financing costs; amortization of intangible assets; equity in (income) loss of our joint ventures; write-down of abandoned leases; derivative fair value (gain) loss, excluding net cash receipts on settled derivative instruments; gain on purchase of Marcellus joint ventures; acquisition expense; non-cash stock compensation expense; non-cash incentive unit expense; restricted unit expense; income tax expense; loss on extinguishment of debt; write-off of deferred financing costs; loss from sale of interest in gas properties; exploration expenses; and net income attributable to noncontrolling interests. Adjusted EBITDAX is not a measure of net income as determined by United States generally accepted accounting principles, or GAAP.

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following table presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDAX to the GAAP financial measure of net income (loss).

(in thousands)	Year Ended December 31,		
	2014	2013	2012
Adjusted EBITDAX reconciliation to net income (loss):			
Net income (loss)	\$219,035	\$(35,776)	\$(19,344)
Interest expense	50,191	17,915	3,487
Depreciation, depletion and amortization	156,270	32,815	14,149
Amortization of deferred financing costs	2,495	5,230	7,220
Amortization of intangible assets	1,156	—	—
Equity in (income) loss of joint ventures	2,656	(19,420)	(1,532)
Write-down of abandoned leases	—	—	2,253
Derivative fair value (gain) loss ⁽¹⁾	(186,477)	(6,891)	1,381
Net cash (payments) receipts on settled derivative instruments ⁽¹⁾	(18,784)	676	879
Gain on purchase of Marcellus joint venture ⁽²⁾	(203,579)	—	—
Acquisition expense	2,339	—	—
Non-cash stock compensation expense	5,553	—	—
Non-cash incentive unit expense	105,961	—	—
Restricted unit expense	—	32,906	—
Income tax expense	91,600	—	—
Loss on extinguishment of debt	7,654	10,622	—
Write-off of deferred financing costs	6,896	—	—
Loss from sale of interest in gas properties	—	4,230	—
Exploration expenses	4,225	9,951	3,275

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Net income attributable to noncontrolling interests	(581)	—	—
Adjusted EBITDAX	\$246,610		\$52,258	\$11,768

The adjustments for the derivative fair value (gains) losses and net cash receipts on settled commodity derivative (1) instruments have the effect of adjusting net income (loss) for changes in the fair value of derivative instruments, which are recognized at the end of each

accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDAX on a cash basis during the period the derivatives settled.

(2) Represents gain incurred on the purchase of the remaining 50% interest in our Marcellus joint venture.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." Also, see the risk factors and other cautionary statements described in "Item 1A. Risk Factors" included elsewhere in this Annual Report. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

Rice Energy is an independent natural gas and oil company engaged in the acquisition, exploration and development of natural gas, oil and NGL properties in the Appalachian Basin. We operate in two business segments, which are managed separately due to their distinct operational differences - the Exploration and Production segment and the Midstream segment.

The year ended December 31, 2014 was a transformative year for Rice Energy, both operationally and structurally. Exiting 2013, we were a private company with 139 employees, 37 net operated producing horizontal Marcellus Shale wells, no operated producing Utica Shale horizontal wells, approximately 90,000 net acres and 27 miles of gathering pipelines. Entering 2015, we are a publicly traded company with 290 employees, 78 net operated producing horizontal Marcellus Shale wells, 2 net operated producing Utica Shale horizontal wells (including the Bigfoot 9H, which tested at a rate of 42 MMcfe/d), approximately 141,000 net acres and a publicly traded midstream subsidiary in Rice Midstream Partners LP. Please see "Item 1. Business—Overview" for more detailed discussion of our significant accomplishments in 2014.

On January 29, 2014, we completed our IPO and related transactions, including our reorganization and concurrent acquisition of Alpha Holdings' 50% interest in our Marcellus joint venture. On December 22, 2014, RMP completed its IPO and related transactions, including our contribution to it of certain gas gathering and compression assets. As a result of the reorganizations that occurred during 2014, our historical financial condition and results of operations for the periods presented in this Annual Report may not be comparable, either from period to period or going forward. For example, information for the period from January 1, 2014 until January 29, 2014, as contained within the year ended December 31, 2014, and for the years ended December 31, 2013 and 2012, pertain to the historical financial statements and results of operations of our accounting predecessor. Whereas our accounting predecessor, Rice Drilling B LLC, was not subject to federal income tax during these periods, we are a corporation subject to federal income tax at a statutory rate of 35% of pretax earnings. In addition, such periods reflect only our 50% equity investment in our Marcellus joint venture. From and after our acquisition of the remaining 50% interest from Alpha Holdings on January 29, 2014, the results of operations of our Marcellus joint venture are consolidated into our results of operations.

In connection with the RMP IPO in December 2014, we contributed to RMP all of our gas gathering and compression assets in Washington and Greene Counties, Pennsylvania in exchange for, among other things, common and subordinated units representing a 50.0% limited partner interest and all of the incentive distribution rights in RMP. In addition to these interests, RMP distributed approximately \$414.4 million of the net proceeds of the RMP IPO raised from the sale of common units representing the remaining 50.0% limited partner interest in RMP. Indirectly through Midstream Holdings, we own and control the general partner of RMP. As such, the results of operations of RMP and the assets we contributed to it remain consolidated into our results of operations following the RMP IPO and concurrent contribution. However, for the period from December 22, 2014 until December 31, 2014, as contained within the year ended December 31, 2014, our results of operations give effect to the noncontrolling interest in RMP attributable to the 50.0% limited partner interest of its public unitholders.

Also in connection with the RMP IPO, we entered into various gas gathering and compression agreements and water distribution services agreements, both intercompany and, in the case of certain gas gathering and compression services in Pennsylvania, with RMP. Prior to December 22, 2014, with certain limited exceptions, our Midstream segment did

not charge fees for providing such services to our Exploration and Production segment.

In connection with these offerings and related restructurings and through 2014, we also enhanced our liquidity and access to capital. Over the course of the year, the borrowing base under our Secured Revolving Credit Facility was increased from \$155.0 million to \$550.0 million. In addition, in connection with the RMP IPO and supported by our new intercompany midstream services agreements, we entered into a new \$300.0 million Midstream Holdings Revolving Credit Facility and RMP entered into the \$450.0 million RMP Revolving Credit Facility. By entering into these new credit facilities, we have separated the credit facility-based capital funding for our Midstream segment from our Exploration and Production segment without reducing the borrowing base of our Senior Secured Revolving Credit Facility.

Sources of Revenues

We derive a substantial majority of our revenues from the sale of natural gas and do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. The following table provides detail of our operating revenues from the consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012.

(in thousands)	Years Ended December 31,		
	2014	2013	2012
Natural gas sales	\$354,860	\$87,847	\$26,743
Oil and NGL sales	4,341	—	—
Firm transportation sales, net	26,237	—	—
Third party gathering revenue	5,504	83	—
Other revenue	—	757	457
Total operating revenues	\$390,942	\$88,687	\$27,200

NYMEX Henry Hub prompt month contract prices are widely-used benchmarks in the pricing of natural gas. The following table provides the high and low prices for NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated.

	Years Ended December 31,		
	2014	2013	2012
NYMEX Henry Hub High (\$/MMBtu)	\$7.94	\$4.52	\$3.77
NYMEX Henry Hub Low (\$/MMBtu)	\$2.75	\$3.08	\$1.83
NYMEX Henry Hub Price (\$/MMBtu)	\$4.32	\$3.73	\$2.75
Less: Average Basis Impact (\$/MMBtu) ⁽¹⁾	(0.84) (0.09) 0.15
Plus: Btu Uplift (MMBtu/Mcf)	0.17	0.18	0.15
Pre-Hedge Realized Price (\$/Mcf)	\$3.65	\$3.82	\$3.05

Differential is calculated by comparing the average NYMEX Henry Hub price to our volume weighted average realized price per MMBtu before hedges, including 50% of the volumes sold by our Marcellus joint venture for the period from January 1, 2014 through January 28, 2014, contained within the year ended December 31, 2014. The remainder of the year ended December 31, 2014 reflects 100% of the volumes sold by our Marcellus joint venture. We sell a substantial majority of our production to a single natural gas marketer, Sequent. For the year ended December 31, 2014, sales to Sequent represented 79% of our total sales. If our natural gas marketers decided to stop purchasing natural gas from us, our revenues could decline and our operating results and financial condition could be harmed. Although a substantial portion of production is purchased by this customer, we do not believe the loss of this customer would have a material adverse effect on our business, as other customers or markets would be accessible to us.

For the year ended December 31, 2014, our Exploration and Production segment accounted for 99% of our operating revenues. While we anticipate that our Midstream segment will represent an increasing portion of our operating revenues in future periods, we expect that a substantial majority of our operating revenues will remain attributable to our Exploration and Production segment.

Principal Components of Our Cost Structure

Lease operating expense. These are the day to day operating costs incurred to maintain production of our natural gas producing wells. Such costs include produced water disposal, maintenance and repairs. Cost levels for these expenses can vary based on supply and demand for oilfield services.

Gathering, compression and transportation. These are costs incurred to bring natural gas to the market. Such costs include the costs to operate and maintain our low- and high-pressure gathering and compression systems as well as fees paid to third parties who operate low- and high-pressure gathering systems that transport our natural gas. We often enter into firm transportation contracts that secure takeaway capacity that includes minimum volume commitments, the cost for which is included in these expenses.

Incentive unit expense. These costs represent non-cash compensation expense for incentive units awarded to certain of our employees by NGP Holdings and Rice Holdings. In connection with our IPO and related corporate reorganization, the holders of incentive units in Rice Appalachia contributed a portion of their incentive units to Rice Holdings and NGP Holdings in return for substantially similar incentive units in such entities. This resulted in the incentive units being deemed to have been modified, and the performance conditions were considered to be probable of occurring. Therefore, their fair values were measured and compensation expense from the date of initial grant through December 31, 2014 has been recognized in the year ended December 31, 2014. The payment obligation as it relates to the incentive units resides with NGP Holdings and Rice Holdings and has not been, and will not be borne by us.

General and administrative expense. These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our exploration and production operations, midstream operations, franchise taxes, audit and other professional fees and legal compliance expenses.

Depreciation, depletion and amortization. Depreciation, depletion and amortization (“DD&A”) includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas. As a “successful efforts” company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts and allocate these costs to each unit of production using the units of production method.

Interest expense. We have financed a portion of our working capital requirements and property acquisitions with borrowings under our revolving credit facilities and our Senior Notes. As a result, we incur interest expense that is affected by the level of drilling, completion and acquisition activities, as well as fluctuations in interest rates and our financing decisions. We will likely continue to incur significant interest expense as we continue to grow. To date, we have not entered into any interest rate hedging arrangements to mitigate the effects of interest rate changes.

Additionally, we capitalized \$0.9 million, \$8.0 million, \$7.7 million of interest expense for the years ended December 31, 2014, 2013 and 2012, respectively.

Derivative fair value gain (loss). We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of natural gas. We recognize gains and losses associated with our open commodity derivative contracts as commodity prices and the associated fair value of our commodity derivative contracts change. The commodity derivative contracts we have in place are not designated as hedges for accounting purposes. Consequently, these commodity derivative contracts are recorded at fair value at each balance sheet date with changes in fair value recognized as a gain or loss in our results of operations. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

Income tax expense. We are a corporation under the Internal Revenue Code, subject to federal income taxes at a statutory rate of 35% of pretax earnings. The reorganization of our business in connection with the closing of our IPO, such that it is now held by a corporation subject to federal income tax, required the recognition of a deferred tax asset or liability for the initial temporary differences at the time of our IPO. The resulting deferred tax liability of approximately \$162.3 million was recorded in equity at the date of our IPO. Based on our deductions primarily related to intangible drilling costs (“IDCs”) that are expected to exceed 2015 earnings, we expect to generate significant net operating loss assets and deferred tax liabilities. We may report and pay state income or franchise taxes in periods where our IDC deductions do not exceed our taxable income or where state income or franchise taxes are determined on another basis.

How We Evaluate Our Operations

In evaluating our financial results, we focus on production, revenues, per unit cash production costs, G&A and our Adjusted EBITDAX. For a reconciliation of Adjusted EBITDAX to net income (loss), see “Item 6. Selected Financial Data-Non-GAAP Financial Measures.” We also evaluate our rates of return on invested capital in our wells, and we measure the expected return of our wells based on EUR and the related costs of acquisition, development and production.

We believe the quality of our assets combined with our technical and managerial expertise can generate attractive rates of return as we develop our core acreage position in the Marcellus and Utica Shales. Additionally, by focusing on concentrated acreage positions, we can build and own centralized midstream infrastructure, including low- and high-pressure gathering lines, compression facilities and water pipeline systems, which enable us to reduce reliance on

third-party operators, minimize costs and increase our returns.

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Results of Operations

Below are some highlights of our consolidated financial and operating results for the years ended December 31, 2014, 2013 and 2012:

Our natural gas, oil and NGL sales were \$359.2 million, \$87.8 million and \$26.7 million in the years ended December 31, 2014, 2013 and 2012, respectively.

Our production volumes were 97,737 MMcfe, 22,995 MMcfe and 8,769 MMcfe in the years ended December 31, 2014, 2013 and 2012, respectively.

Our firm transportation sales, net were \$26.2 million, for the year ended December 31, 2014.

Our per unit cash production costs were \$0.72 per Mcfe, \$0.86 per Mcfe and \$1.01 per Mcfe in the years ended December 31, 2014, 2013 and 2012, respectively.

Our G&A expenses were \$56.0 million, \$17.0 million and \$7.6 million in the years ended December 31, 2014, 2013 and 2012, respectively.

The following tables set forth selected operating and financial data for the year ended December 31, 2014 compared to the year ended December 31, 2013 and the year ended December 31, 2012 compared to the year ended December 31, 2012:

	Year Ended December 31,			Year Ended December 31,		
	2014	2013	Change	2013	2012	Change
Natural gas sales (in thousands)	\$354,860	\$87,847	\$267,013	\$87,847	\$26,743	\$61,104
Oil and NGL sales (in thousands)	4,341	—	4,341	—	—	—
Natural gas, oil and NGL sales (in thousands)	\$359,201	\$87,847	\$271,354	\$87,847	\$26,743	\$61,104
Firm transportation sales, net (in thousands)	\$26,237	\$—	\$26,237	\$—	\$—	\$—
Natural gas production (MMcf)	97,172	22,995	74,177	22,995	8,769	14,226
Oil and NGL production (MBbls)	94	—	94	—	—	—
Total production (MMcfe)	97,737	22,995	74,742	22,995	8,769	14,226
Average natural gas prices before effects of hedges per Mcf	\$3.65	\$3.82	\$(0.17)	\$3.82	\$3.05	\$0.77
Average realized natural gas prices after effects of hedges per Mcf ⁽¹⁾	3.46	3.85	(0.39)	3.85	3.15	0.70
Average oil and NGL prices per Bbl	46.07	—	46.07	—	—	—
Average costs per Mcfe						
Lease operating	\$0.26	\$0.36	\$(0.10)	\$0.36	\$0.42	\$(0.06)
Gathering, compression and transportation	0.41	0.43	(0.02)	0.43	0.43	—
Production taxes and impact fees	0.05	0.07	(0.02)	0.07	0.16	(0.09)
General and administrative	0.57	0.74	(0.17)	0.74	0.87	(0.13)
Depreciation, depletion and amortization	1.60	1.43	0.17	1.43	1.61	(0.18)

(1) The effect of hedges includes realized gains and losses on commodity derivative transactions.

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(in thousands, except per share data)	Year Ended December 31,			Year Ended December 31,		
	2014	2013	Change	2013	2012	Change
Operating revenues:						
Natural gas, oil and NGL sales	\$359,201	\$87,847	\$271,354	\$87,847	\$26,743	\$61,104
Firm transportation sales, net	26,237	—	26,237	—	—	—
Other revenue	5,504	840	4,664	840	457	383
Total operating revenues	390,942	88,687	302,255	88,687	27,200	61,487
Operating expenses:						
Lease operating	24,971	8,309	16,662	8,309	3,688	4,621
Gathering, compression and transportation	40,225	9,774	30,451	9,774	3,754	6,020
Production taxes and impact fees	4,647	1,629	3,018	1,629	1,382	247
Exploration	4,225	9,951	(5,726)	9,951	3,275	6,676
Incentive unit expense	105,961	—	105,961	—	—	—
Restricted unit expense	—	32,906	(32,906)	32,906	—	32,906
Stock compensation expense	5,553	—	5,553	—	—	—
General and administrative	56,017	16,953	39,064	16,953	7,599	9,354
Depreciation, depletion and amortization	156,270	32,815	123,455	32,815	14,149	18,666
Acquisition expense	2,339	—	2,339	—	—	—
Amortization of intangible assets	1,156	—	1,156	—	—	—
Write-down of abandoned leases	—	—	—	—	2,253	(2,253)
Loss from sale of interest in gas properties	—	4,230	(4,230)	4,230	—	4,230
Total operating expenses	401,364	116,567	284,797	116,567	36,100	80,467
Operating loss	(10,422)	(27,880)	17,458	(27,880)	(8,900)	(18,980)
Interest expense	(50,191)	(17,915)	(32,276)	(17,915)	(3,487)	(14,428)
Gain on purchase of Marcellus joint venture	203,579	—	203,579	—	—	—
Other income (loss)	893	(440)	1,333	(440)	112	(552)
Gain (loss) on derivative instruments	186,477	6,891	179,586	6,891	(1,381)	8,272
Amortization of deferred financing costs	(2,495)	(5,230)	2,735	(5,230)	(7,220)	1,990
Loss on extinguishment of debt	(7,654)	(10,622)	2,968	(10,622)	—	(10,622)
Write-off of deferred financing costs	(6,896)	—	(6,896)	—	—	—
Equity in income (loss) of joint ventures	(2,656)	19,420	(22,076)	19,420	1,532	17,888
Income (loss) before income taxes	310,635	(35,776)	346,411	(35,776)	(19,344)	(16,432)
Income tax expense	(91,600)	—	(91,600)	—	—	—
Net income (loss)	219,035	(35,776)	254,811	(35,776)	(19,344)	(16,432)
Less: Net income attributable to noncontrolling interests	(581)	—	(581)	—	—	—
Net income (loss) attributable to Rice Energy Inc.	\$218,454	\$(35,776)	\$254,230	\$(35,776)	\$(19,344)	\$(16,432)

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Weighted average number of shares of common stock - basic	128,151	80,442	47,709	80,442	58,232	22,210
Weighted average number of shares of common stock - diluted	128,225	80,442	47,783	80,442	58,232	22,210
Earnings (loss) per share—basic	\$1.70	\$(0.44)) \$2.14	\$(0.44)) \$(0.33)) \$(0.11)
Earnings (loss) per share—diluted	\$1.70	\$(0.44)) \$2.14	\$(0.44)) \$(0.33)) \$(0.11)

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

Natural gas, oil and NGL sales. The \$271.4 million increase in natural gas, oil and NGL sales was mainly a result of an increase in production in 2014 compared to 2013. The increase in production was a result of increased drilling and completion activity in 2014, mainly in Washington County, Pennsylvania and Belmont County, Ohio, production from the acquisition of Alpha Holdings' 50% interest in our Marcellus joint venture and production from seven wells acquired in our Greene County, Pennsylvania acreage acquisition on August 1, 2014.

Firm transportation sales, net. Operating revenues for 2014 were positively impacted by approximately \$26.2 million in firm transportation sales, net, from the sale of unutilized pipeline capacity to third parties in the third and fourth quarters of 2014.

Lease operating expenses. The \$16.7 million increase in lease operating expenses is attributable to an increase in the number of producing wells in 2014 as compared to the prior year. However, lease operating expenses per unit of production decreased due to improved efficiencies, primarily due to more producing wells per pad and lower fixed costs per well.

Gathering, compression and transportation. The \$30.5 million increase in gathering, compression and transportation expenses is primarily attributable to increased firm transportation contracts in 2014 compared to 2013.

Incentive unit expense. The \$106.0 million incentive unit expense was due to \$86.2 million of non-cash compensation expense recognized in relation to the incentive unit awards based on fair market value assumptions in 2014.

Additionally, NGP Holdings paid approximately \$12.0 million to holders of certain NGP Holdings incentive units as a result of our August 2014 Equity Offering and \$4.4 million at our IPO; Daniel J. Rice III also made a payment at IPO of approximately \$3.4 million related to his incentive unit burden concurrent with our IPO. For additional information, see Note 13 in the notes to the consolidated financial statements under Item 8 of this Annual Report.

G&A. The \$39.1 million increase was primarily attributable to the additions of personnel to support our growth activities and related salary and employee benefits. At December 31, 2014, we had 290 employees as compared to 139 employees at December 31, 2013. Additionally, we also incurred increased costs as a result of being a public company.

DD&A. The \$123.5 million increase was a result of an increase in production and greater number of producing wells in 2014 compared to 2013. This is consistent with our expanded drilling program and increased production during the year.

Interest expense. The \$32.3 million increase in interest expense was a result of our issuance of \$900.0 million of Senior Notes and higher levels of average borrowings outstanding during 2014 in order to fund our capital programs.

Gain on purchase of Marcellus joint venture. The \$203.6 million gain on acquisition in the first quarter of 2014 was attributable to our acquisition of Alpha Holdings' 50% interest in our Marcellus joint venture in connection with the closing of our IPO (the "Marcellus JV Buy-In"). As a result of our acquisition of the remaining 50% ownership in our Marcellus joint venture, we were required to remeasure our equity investment at fair value, which resulted in the non-recurring gain.

Gain on derivative instruments. The \$186.5 million gain on derivative contracts in 2014 was comprised of \$205.3 million in unrealized gains and \$18.8 million of cash payments on the settlement of maturing contracts. In 2013, the \$6.9 million gain was comprised of \$6.2 million in unrealized gains and \$0.7 million of cash receipts on the settlement of maturing contracts.

Equity in income (loss) of joint ventures. The \$22.1 million decrease in equity income of joint ventures is the result of our acquisition of the remaining 50% interest in our Marcellus joint venture in January 2014, as we consolidate the operations of our Marcellus joint venture subsequent to the acquisition.

Income tax expense. The \$91.6 million income tax expense in 2014 is a result of our status as a corporation subject to federal and state income tax subsequent to our IPO. We did not report any income tax benefit or expense for periods prior to the consummation of our IPO in January 2014 because Rice Drilling B, our accounting predecessor, is a limited liability company that was not subject to federal income tax.

Noncontrolling interest. The net income attributable to noncontrolling interest was \$0.6 million in 2014. The noncontrolling interest represents limited partner interests in RMP for the period subsequent to the RMP IPO on December 22, 2014.

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

Natural gas sales revenues. The \$61.1 million increase was a result of an increase in production of 14,226 MMcf in 2013 compared to the prior year. The increase in production was a result of increased drilling and completion activity in Washington County, Pennsylvania.

Lease operating expenses. The \$4.6 million increase in lease operating expenses is attributable to higher production during 2013. However, lease operating expenses per unit of production decreased due to having more wells in early stages of production in 2013 as compared to 2012.

Gathering, compression and transportation. The \$6.0 million increase in gathering, compression and transportation expenses is primarily attributable to increased production. The cost per Mcf of these expenses increased during 2013

primarily as a result of increased utilization of firm transportation.

Restricted unit expense. The \$32.9 million increase in restricted unit expense relates to an increase in the fair value of the units during 2013. For a description of the restricted units, please see Note 9 to the audited consolidated financial statements of

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our predecessor. In connection with our IPO, the restricted units were exchanged for shares of our common stock. Accordingly, we will not recognize such restricted unit expense subsequent to the exchange.

G&A. The \$9.4 million increase was primarily attributable to the additions of personnel to support our growth activities.

DD&A. The \$18.7 million increase was a result of higher average capitalized costs in 2013 compared to the prior year. The increase in capitalized costs is consistent with our expanded drilling program and increased production during the period.

Write-down of abandoned leases. The \$2.3 million write-down in 2012 was attributable to our abandonment of certain leases that are outside our core areas of drilling focus.

Exploration expense. The \$6.7 million increase in 2013 was primarily the result of the \$8.1 million write-off of costs associated with the abandonment of the Bigfoot 7H in the fourth quarter of 2013.

(Gain) loss from sale of interest in gas properties. The \$4.2 million loss from sale of interest in gas properties was attributable to the sale of interests in noncore assets in Lycoming County, Pennsylvania.

Gain (loss) on derivative instruments. The \$6.9 million gain on derivatives contracts in 2013 was comprised of \$6.2 million in unrealized gains and \$0.7 million of cash receipts received on settlement of maturing contracts. In 2012, the \$1.4 million loss was comprised of \$2.3 million in unrealized losses and \$0.9 million of cash receipts received on settlement of maturing contracts. The gain in 2013 was due to a decrease in market prices after we executed significant derivative contracts.

Interest expense. The \$14.4 million increase was a result of higher levels of average borrowings outstanding during 2013 in order to fund our drilling programs.

Loss on extinguishment of debt. The \$10.6 million loss on extinguishment of debt in 2013 was attributable to our repurchasing \$53.1 million of outstanding convertible debentures, resulting in a put premium of \$10.6 million being paid in accordance with the terms thereof.

Equity in income (loss) of joint ventures. The \$17.9 million increase was primarily a result of operations at our Marcellus joint venture. Approximately \$1.7 million of the increased income from our Marcellus joint venture was attributable to net realized gains associated with its hedging program. Substantially all of the remaining increase in income was due to higher revenues, attributable to increased production volumes resulting from the execution of our Marcellus joint venture's drilling program.

Segment Information

For the year ended December 31, 2014, we have begun to report our midstream operations as a reportable segment. Prior to 2014, such operations were not a significant portion of our business as compared to our exploration and production operations. The following table provides a summary of our segment operating results for the year ended December 31, 2014:

(in thousands)	Exploration and Production	Midstream	Elimination of Intersegment Transactions	Consolidated Total
Operating revenues:				
Natural gas, oil and NGL sales	\$359,201	\$—	\$—	\$359,201
Firm transportation sales, net	26,237	—	—	26,237
Other revenue	—	7,300	(1,796)	5,504
Total operating revenues	385,438	7,300	(1,796)	390,942
Operating expenses:				
Depreciation, depletion and amortization	\$151,900	\$4,370	\$—	\$156,270
Exploration	4,018	207	—	4,225
Lease operating	24,971	—	—	24,971
Gathering, compression and transportation	37,414	4,607	(1,796)	40,225
Production taxes and fees	4,647	—	—	4,647
Incentive unit expense	86,020	19,941	—	105,961
Stock compensation expense	4,532	1,021	—	5,553
Acquisition costs	820	1,519	—	2,339
Amortization of intangible assets	—	1,156	—	1,156
General and administrative expenses	41,697	14,320	—	56,017
Total operating expenses	\$356,019	\$47,141	\$(1,796)	\$401,364
Operating income (loss)	\$29,419	\$(39,841)	\$—	\$(10,422)

In 2014, our midstream segment generated \$7.3 million of midstream revenues, of which \$1.8 million resulted from intercompany gathering charges paid by us subsequent to the RMP IPO on December 22, 2014 that were eliminated as intercompany transactions in our consolidated financial statements. We expect the intercompany gathering charges to significantly increase in future periods.

Outlook

We derive a substantial majority of our revenues from the sale of natural gas that is produced from our interests in properties located in the Marcellus Shale. In the coming years, we expect to derive an increasing amount of our revenues from the sale of natural gas, and in a more limited amount NGLs, that are produced from our interests in properties located in the Utica Shale. Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy.

Natural gas prices have historically been volatile and may fluctuate widely in the future due to a variety of factors, including but not limited to, prevailing economic conditions, supply and demand of hydrocarbons in the marketplace and geopolitical events such as wars or natural disasters. For example, the Henry Hub spot market price had declined from a high of \$7.94 per MMBtu on March 5, 2014 to a low of \$2.75 per MMBtu on December 25, 2014. In the future, we expect to be increasingly subject to fluctuations in oil and NGL prices. Sustained periods of low commodity prices could materially and adversely affect our financial condition, our results of operations, the quantities of natural gas that we can economically produce and our ability to access capital.

We use commodity derivative instruments, such as swaps, puts and collars, to manage and reduce price volatility and other market risks associated with our natural gas production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from

commodity price increases. Please see “—Commodity Hedging Activities.” In addition, we have entered into long-term firm transportation arrangements

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pursuant to which our production is shipped to markets that we expect to be less impacted by basis differentials. In recent years, the cost of new firm transportation projects has risen significantly concurrent with the increasing basis differentials experienced in the Appalachian Basin. While entering into these firm transportation arrangements provides flow assurance for our natural gas production, there can be no assurance that the net impact of entering into such arrangements, after giving effect to their costs, will result in more favorable sales prices for our production in the future than local pricing. As such, our net sales prices may be materially less than NYMEX Henry Hub prices as a result of basis differentials and/or firm transportation costs.

Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us. In 2015, we plan to invest \$1,070.0 million in our operations, including \$340.0 million for drilling and completion in the Marcellus Shale, \$220.0 million for drilling and completion in the Utica Shale, \$120.0 million for leasehold acquisitions and \$390.0 million for midstream infrastructure development, including \$180.0 million expected to be invested by RMP. We expect to fund our 2015 capital expenditures with cash on hand, cash generated by operations and borrowings under our revolving credit facilities. Our 2015 capital budget may be further adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas prices decline to levels below our acceptable levels, or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe will have the highest expected rates of return and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in commodity prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control.

We believe that cash on hand, operating cash flows and available borrowings under our revolving credit facilities will be sufficient to meet our current cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies. However, to the extent that we consider market conditions favorable, we may access the capital markets to raise capital from time to time to fund acquisitions or future capital expenditures, pay down our Senior Secured Revolving Credit Facility and for general working capital purposes. See “—Debt Agreements” below for additional details on our outstanding borrowings and available liquidity under our various financing arrangements.

Capital Resources and Liquidity

Our primary sources of liquidity have been the proceeds from equity and debt financings, equity contributions from our sponsors and borrowings under our Senior Secured Revolving Credit Facility. Our primary use of capital has been the acquisition and development of natural gas properties and associated midstream infrastructure. As we pursue reserve and production growth, we monitor which capital resources, including equity and debt financings, are available to us to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. We also expect to fund a portion of these requirements with cash flow from operations as we continue to bring additional production online.

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was \$85.1 million for the year ended December 31, 2014, compared to \$33.7 million of net cash provided by operating activities for the year ended December 31, 2013. The change in operating cash flow was primarily the result of higher production in 2014.

Net cash provided by operating activities was \$33.7 million for the year ended December 31, 2013 compared to \$3.0 million of net cash used in operating activities for the year ended December 31, 2012. The change in operating cash flow was primarily the result of a \$2.2 million increase in net income before DD&A, \$17.9 million of which was attributable to undistributed earnings from our Marcellus joint venture and changes in working capital.

Cash Flow Used in Investing Activities

During the year ended December 31, 2014 cash flows used in investing activities increased to \$1,481.5 million from \$458.6 million for the year ended December 31, 2013. This was primarily related to increased capital expenditures for drilling, development and acquisition costs. Additionally, our August 2014 acquisition of approximately 22,000 net acres and 12 developed Marcellus wells in southwestern Greene County, Pennsylvania, our April 2014 acquisition of certain gas gathering assets in eastern Washington and Greene Counties, Pennsylvania and our January 2014 acquisition of the remaining 50% of our Marcellus Shale joint venture, resulted in a net cash outflow of \$524.1 million.

During the year ended December 31, 2013 cash flows used in investing activities increased to \$458.6 million from \$120.0 million for the year ended December 31, 2012. This was primarily related to increased capital expenditures for drilling, development and acquisition costs.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities of \$1,620.9 million during the year ended December 31, 2014 was primarily the result of the proceeds from our IPO, our Senior Notes Offering, the RMP IPO and the August 2014 Equity Offering, which was partially offset by repayments of debt. Net cash provided by financing activities of \$448.0 million during the year ended December 31, 2013 was primarily related to borrowings under our Second Lien Term Loan facility. Net cash provided by financing activities of \$127.1 million during the year ended December 31, 2012 was primarily attributable to capital contributions from our members and net borrowings under debt agreements that are further described in "Debt Agreements" below.

Debt Agreements

6.25% Senior Notes Due 2022

On April 25, 2014, we offered \$900.0 million in aggregate principal amounts of our Senior Notes in the Senior Notes Offering to eligible purchasers under Rule 144A and Regulation S of the Securities Act, which resulted in net proceeds to us of \$882.7 million after deducting estimated expenses and underwriting discounts and commissions of approximately \$17.3 million. We used \$301.8 million of the net proceeds to repay and retire the Second Lien Term Loan Facility and expect to use the remainder to fund our capital expenditure plan.

The Senior Notes will mature on May 1, 2022, and interest is payable on the Senior Notes on each May 1 and November 1. At any time prior to May 1, 2017, we may redeem up to 35% of the Senior Notes at a redemption price of 106.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Senior Notes remains outstanding after such redemption. Prior to May 1, 2017, we may redeem some or all of the notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. Upon the occurrence of a Change of Control (as defined in the Indenture), unless we have exercised our optional redemption right in respect of the Senior Notes, the holders of the Senior Notes will have the right to require us to repurchase all or a portion of the Senior Notes at a price equal to 101% of the aggregate principal amount of the Senior Notes, plus any accrued and unpaid interest to the date of purchase. On or after May 1, 2017, we may redeem some or all of the Senior Notes at redemption prices (expressed as percentages of principal amount) equal to 104.688% for the twelve-month period beginning on May 1, 2017, 103.125% for the twelve-month period beginning May 1, 2018, 101.563% for the twelve-month period beginning on May 1, 2019 and 100.000% beginning on May 1, 2020, plus accrued and unpaid interest to the redemption date.

The Senior Notes are our senior unsecured obligations, rank equally in right of payment with all of our existing and future senior debt, and will rank senior in right of payment to all of our future subordinated debt. The Senior Notes will be effectively subordinated to all of our existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

The Indenture restricts our ability and the ability of our restricted subsidiaries to: (i) incur or guarantee additional debt or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated debt; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; (vii) transfer and sell assets; and (viii) create unrestricted

subsidiaries. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Senior Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and we and our subsidiaries will cease to be subject to such covenants.

In connection with the issuance and sale of the Senior Notes, we and the Guarantors entered into a registration rights agreement with the Initial Purchasers, dated April 25, 2014. Pursuant to the registration rights agreement, we completed an exchange of the Senior Notes for registered notes that have substantially identical terms as the Senior Notes.

Senior Secured Revolving Credit Facility

In April 2013, we entered into our \$500.0 million Senior Secured Revolving Credit Facility. Concurrently with the closing of our IPO, on January 29, 2014, the credit agreement governing the Senior Secured Revolving Credit Facility was amended to, among other things, allow for the corporate reorganization that was completed simultaneously with the closing of our IPO, add us as a guarantor, increase the maximum commitment amount to \$1.5 billion, increase the borrowing base to \$350.0 million as a result of the Marcellus JV Buy-In and lower the interest rate owed on amounts borrowed under the Senior Secured Revolving Credit Facility. We used a portion of the net proceeds of our IPO to repay \$115.0 million of borrowings under our Senior Secured Revolving Credit Facility and \$75.4 million of borrowings outstanding under the revolving credit facility of our Marcellus joint venture.

In April 2014, concurrently with the Senior Notes Offering, we, as borrower, and Rice Drilling B, as predecessor borrower, amended and restated the credit agreement governing the Senior Secured Revolving Credit Facility (the "Amended Credit Agreement") to, among other things, assign all of Rice Drilling B's rights and obligations under the Senior Secured Revolving Credit Facility to us, and we assumed all such rights and obligations as borrower under the Amended Credit Agreement.

Furthermore, the Amended Credit Agreement (i) allowed for the Senior Notes Offering and (ii) provided that we did not incur an immediate reduction in the borrowing base under the Senior Secured Revolving Credit Facility as a result of the Senior Notes Offering. The Amended Credit Agreement also extended the maturity date of the Senior Secured Revolving Credit Facility from April 25, 2018 to January 29, 2019. As of December 31, 2014, the borrowing base was \$550.0 million and the sublimit for letters of credit was \$100.0 million. The Company had zero borrowings outstanding and \$66.8 million in letters of credit outstanding under its Amended Credit Agreement as of December 31, 2014, resulting in availability of \$483.2 million. The next redetermination is scheduled for April 2015.

Eurodollar loans under the Senior Secured Revolving Credit Facility bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of borrowing base utilized.

The Amended Credit Agreement is secured by liens on at least 80% of the proved oil and gas reserves of us and our subsidiaries (other than any subsidiary that is designated as an unrestricted subsidiary including Midstream Holdings and its subsidiaries), as well as significant unproved acreage and substantially all of the personal property of us and such restricted subsidiaries, and the Amended Credit Agreement is guaranteed by such restricted subsidiaries. The Amended Credit Agreement contains restrictive covenants that limit the ability of us and our restricted subsidiaries to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make or declare dividends;
- hedge future production or interest rates;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Amended Credit Agreement also requires us to maintain certain financial ratios, which are measured at the end of each calendar quarter:

a current ratio, which is the ratio of consolidated current assets (including unused commitments under the Amended Credit Agreement and excluding non-cash derivative assets) to consolidated current liabilities (excluding current maturities under the Amended Credit Agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX (as such term is defined in the Amended Credit Agreement) based on the trailing twelve month period to consolidated interest expense, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2014.

Second Lien Term Loan Facility

On April 25, 2013, Rice Drilling B entered into a Second Lien Term Loan Facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders in an aggregate principal amount of \$300.0 million. Rice Drilling B estimated the discount on issuance of this instrument based upon an estimate of market rates at the inception of the instrument and recorded a discount of \$4.5 million. The discount was being amortized over the life of the note using an effective interest rate of 0.284% using the effective yield method. On April 25, 2014, we used \$301.8 million of the net proceeds from our Senior Notes Offering to repay and retire the Second Lien Term Loan Facility. The \$301.8 million included the outstanding principal balance of \$297.0 million, a prepayment premium in the amount of approximately \$3.0 million, and accrued but unpaid interest of \$1.8 million.

Midstream Holdings Revolving Credit Facility

On December 22, 2014, Midstream Holdings entered into a revolving credit facility (“Midstream Holdings Revolving Credit Facility”) with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders with a maximum credit amount of \$300.0 million and a sublimit for letters of credit of \$25.0 million. As of December 31, 2014, Midstream Holdings had no borrowings outstanding and no letters of credit under this facility. The credit facility is available to fund working capital requirements and capital expenditures and to purchase assets and matures on December 22, 2019. Rice Olympus Midstream LLC, Rice Water Services (OH) LLC and Rice Water Services (PA) LLC are the guarantors of the obligations under the credit facility.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Midstream Holdings has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the applicable LIBOR Rate plus an applicable margin ranging from 225 to 300 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 125 to 200 basis points, depending on the leverage ratio then in effect. Midstream Holdings will also pay a commitment fee based on the undrawn commitment amount ranging from 37.5 to 50 basis points.

The Midstream Holdings Revolving Credit Facility is secured by mortgages and other security interests on substantially all of the properties of, and guarantees from, Midstream Holdings and its restricted subsidiaries (which do not include RMP or Rice Midstream Management LLC, a Delaware limited liability company and general partner of RMP or Rice Energy and its subsidiaries other than Midstream Holdings).

The Midstream Holdings Revolving Credit Facility limits Midstream Holdings’ and its restricted subsidiaries ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
 - merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The Midstream Holdings Revolving Credit Facility will also require Midstream Holdings' to maintain the following financial ratios:

an interest coverage ratio, which is the ratio of Midstream Holdings' consolidated EBITDA (as defined within the Midstream Holdings Revolving Credit Facility) to our consolidated current interest expense of at least 2.50 to 1.0 at the end of each fiscal quarter; and

a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 4.25 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2014.

RMP Revolving Credit Facility

On December 22, 2014, Rice Midstream OpCo entered into a revolving credit facility ("RMP Revolving Credit Facility") with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders with a maximum credit amount of \$450.0 million and a sublimit for letters of credit of \$50.0 million. As of December 31, 2014, Rice Midstream OpCo had no borrowings outstanding and no letters of credit under this facility. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. The RMP Revolving Credit Facility matures on December 22, 2019. RMP and its restricted subsidiaries are the guarantors of the obligations under the credit facility.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Rice Midstream OpCo has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the applicable LIBOR Rate plus an applicable margin ranging from 175 to 275 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 75 to 175 basis points, depending on the leverage ratio then in effect. Rice Midstream OpCo also pays a commitment fee based on the undrawn commitment amount ranging from 35 to 50 basis points.

The RMP Revolving Credit Facility is secured by mortgages and other security interests on substantially all of RMP's properties and guarantees from RMP and its restricted subsidiaries.

The RMP Revolving Credit Facility limits the ability of RMP and its restricted subsidiaries to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
 - merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The RMP Revolving Credit Facility also requires RMP to maintain the following financial ratios:

an interest coverage ratio, which is the ratio of the RMP's consolidated EBITDA (as defined within the revolving credit facility) to its consolidated current interest expense of at least 2.50 to 1.0 at the end of each fiscal quarter;

a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 4.75 to 1.0, and after electing to issue senior unsecured notes, a consolidated total leverage ratio of not more than 5.25 to 1.0, and, in each case, with certain increases in the permitted total leverage ratio following the completion of a material acquisition; and

if RMP elects to issue senior unsecured notes, a consolidated senior secured leverage ratio, which is the ratio of consolidated senior secured debt to consolidated EBITDA, of not more than 3.50 to 1.0.

RMP was in compliance with such covenants and ratios as of December 31, 2014.

Convertible Debentures

In June of 2011, Rice Drilling B sold \$60.0 million of its 12% Senior Subordinated Convertible Debentures due 2014 (the “Debentures”) in a private placement to certain accredited investors as defined in Rule 501 of Regulation D. The Debentures accrued interest at 12% per year payable monthly in arrears by the 15th day of the month and had a scheduled maturity date of July 31, 2014. The Debentures were Rice Drilling B’s unsecured senior obligations and ranked equally with all of Rice Drilling B’s then-current and future senior unsecured indebtedness.

In connection with the IPO, the Debentures and warrants of Rice Drilling B were amended to become convertible or exercisable for shares of our common stock. On February 28, 2014, Rice Drilling B issued a redemption notice on the remaining Debentures, which set a redemption date of March 28, 2014. Prior to the redemption date, \$6.6 million of the Debentures were converted into 570,945 shares of Rice Energy Inc. common stock. The premium of \$0.1 million was recorded to expense in the year ended December 31, 2014. As of December 31, 2014, the remaining principal balance was \$0.2 million.

Commodity Hedging Activities

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

To mitigate the potential negative impact on our cash flow caused by changes in natural gas prices, we have entered into financial commodity derivative contracts in the form of swaps, zero cost collars, calls, puts and basis swaps to ensure that we receive minimum prices for a portion of our future natural gas production when management believes that favorable future prices can be secured. We typically hedge the NYMEX Henry Hub price for natural gas. The Amended Credit Agreement adjusted our hedging limitation. In the prior Senior Secured Revolving Credit Facility agreement, we were permitted to hedge volumes based on a percentage of expected production from proved reserve volumes. We are now permitted to hedge the greater of (i) the percentage of internally forecasted production (Column A) and (ii) the percentage of proved reserve volumes (Column B) according to the table below.

Months next succeeding the time as of which compliance is measured	Column A	Column B	
Months 1 through 12	75	% 85	%
Months 13 through 24	50	% 85	%
Months 25 through 36	40	% 85	%
Months 37 through 48	25	% 65	%
Months 49 through 60	15	% 65	%

Our hedging activities are intended to support natural gas prices at targeted levels and to manage our exposure to natural gas price fluctuations. The counterparty is required to make a payment to us for the difference between the floor price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the floor price. We are required to make a payment to the counterparty for the difference between the ceiling price and the settlement price if the ceiling price is below the settlement price. These contracts may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty and zero cost collars that set a floor and ceiling price for the hedged production. For a description of our commodity derivative contracts, please see Notes 4 and 5 under Item 8 in the notes to consolidated financial statements. During the fourth quarter of 2013, we began hedging basis differentials associated with our natural gas production. We elected not to designate our current portfolio of commodity derivative contracts as hedges for accounting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings. Please read “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for additional discussion of our commodity derivative contracts.

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us,

which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have derivative instruments in place with six different

counterparties. As of December 31, 2014, our contracts with Wells Fargo Bank N.A. accounted for 41% of the net fair market value of our derivative assets. We believe that Wells Fargo Bank N.A. is an acceptable credit risk. We are not required to provide credit support or collateral to Wells Fargo Bank N.A. under current contracts, nor are they required to provide credit support or collateral to us. As of December 31, 2014 we did not have any past due receivables from counterparties.

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

(in thousands)	Payments due by period						Total
	For the Year Ended December 31,						
	2015	2016	2017	2018	2019	Thereafter	
Senior Notes Due 2022	\$56,250	\$56,250	\$56,250	\$56,250	\$56,250	\$1,030,993	\$1,312,243
Drilling rig commitments ⁽¹⁾	49,473	21,194	6,949	—	—	—	77,616
Gathering and firm transportation	94,292	117,211	136,833	197,675	222,559	4,123,263	4,891,833
Lease obligations	30,702	3,769	482	28	—	—	34,981
Asset retirement obligations ⁽²⁾	—	—	—	—	—	74,509	74,509
Other	3,025	2,276	2,252	1,454	171	—	9,178
Total	\$233,742	\$200,700	\$202,766	\$255,407	\$278,980	\$5,228,765	\$6,400,360

As of December 31, 2014, we had seven drilling rigs under contract, of which five expire in 2015 and two expire in 2017. Any other rig performing work for us is done on a well-by-well basis and therefore can be released without (1) penalty at the conclusion of drilling on the current well. These types of drilling obligations have not been included in the table above. The values in the table represent the gross amounts that we are committed to pay. However, we will record in our consolidated financial statements our proportionate share based on our working interest.

(2) Represents gross retirement costs with no discounting impact.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. See Note 1 of the notes to the consolidated financial statements for an expanded discussion of our significant accounting policies and estimates made by management.

Revenue Recognition

Sales of natural gas, NGLs and oil are recognized when the products 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. Natural gas is sold by the Company under contracts with the Company's natural gas marketers. Pricing provisions are tied to the Platts Gas Daily market prices.

Gas Properties

We use the successful efforts method of accounting for gas-producing activities. Costs to acquire mineral interests in gas properties and to drill and equip exploratory wells that result in proved reserves are capitalized. Costs to drill exploratory wells that do not identify proved reserves as well as geological and geophysical costs and costs of

carrying and retaining unproved properties are expensed.

Unproved gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Capitalized costs of producing gas properties and support equipment directly related to such properties, after considering estimated residual salvage values, are depreciated and depleted by the units of production method. Support equipment and other property and equipment not directly related to gas properties are depreciated over their estimated useful lives.

Management's estimates of proved reserves are based on quantities of natural gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic conditions. External engineers prepare the annual reserve and economic evaluation of all properties on a well-by-well basis. Additionally, we adjust natural gas reserves for major well rework or abandonment during the year as needed. The process of estimating and evaluating natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering, and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect our DD&A expense, a change in our estimated reserves could have a material effect on our net income or loss.

Upon the sale of an entire interest in an unproved property for cash, a gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained unless the proceeds received are in excess of the cost basis which would result in gain on sale.

Derivative Financial Information

We enter into derivative transactions in order to manage our exposure to gas price volatility, including commodity swap agreements, basis swap agreements, collar agreements and other similar agreements relating to the price risk associated with a portion of our production. To the extent legal right of offset with a counterparty exists, we report derivative assets and liabilities on a net basis. We have exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation, however, we actively monitor the creditworthiness of counterparties and assess the impact, if any, on our derivative position. We record derivative instruments on the consolidated balance sheets as either an asset or a liability measured at fair value and records changes in the fair value of derivatives in the consolidated statements of operations as they occur.

Asset Retirement Obligations

We record the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. For gas properties, this is the period in which a gas well is acquired or drilled. Our retirement obligations relate to the abandonment of gas-producing facilities and include costs to reclaim drilling sites and dismantle and relocate or dispose of gathering systems, wells, and related structures. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining lives of those wells based on reserve estimates.

When a new liability is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. To the extent future revisions to assumptions impact the present value of the existing asset retirement obligation a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. The liability is accreted to its present value each period and the capitalized cost is depreciated over the units of production basis.

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment at least annually, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Step 1 is to determine the fair value of the reporting unit and if such fair value is greater than the carrying value a Step 2 analysis is not required. However, in the event a Step 2 analysis is required, if the carrying amount of the goodwill of the identifiable assets exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. Management performed a Step 1 analysis for 2014 and determined the fair value of our business using the income and market approaches. This type of analyses require us to make assumptions and estimates regarding industry and economic factors such as production volumes, commodity pricing, discount rates and natural gas reserves. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations. No impairments for goodwill have been recorded for the year ended December 31, 2014.

Depletion

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit-of-production method over proved reserves. Depletion of the costs of wells and related equipment and facilities, including capitalized asset retirement costs, is computed using proved developed reserves. The reserve base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves.

Incentive Units

We recognize non-cash compensation expense for incentive units awarded to certain of our employees by NGP Holdings and Rice Holdings. In connection with our IPO and related corporate reorganization, the holders of incentive units in Rice Appalachia contributed a portion of their incentive units to Rice Holdings and NGP Holdings in return for substantially similar incentive units in such entities. This resulted in the incentive units being deemed to have been modified, and the performance conditions were considered to be probable of occurring. Therefore, their fair values were measured and compensation expense from the date of initial grant through December 31, 2014 has been recognized in the year ended December 31, 2014.

It is currently expected that the NGP Holdings incentive units will be satisfied in cash and the Rice Holdings incentive units will be satisfied in shares of our common stock held by Rice Holdings. As a result of these different manners of payment satisfaction, the incentive units are accounted for differently, with the NGP Holdings incentive units being accounted for as liability awards and the Rice Holdings incentive units being accounted for as equity awards. For

the NGP Holdings incentive units, for the year ended December 31, 2014 and for future reporting periods, the fair value used to determine the applicable compensation expense will be re-measured at each reporting period. For the Rice Holdings incentive units, the fair value of the incentive units was measured as of January 29, 2014, the date of modification. This fair value will underlie compensation expense charges for future reporting periods over the remaining service period.

Determination of the fair value of the awards requires judgments and estimates regarding, among other things, the appropriate methodologies to follow in valuing the incentive units and the related inputs required by those valuation methodologies. The fair values underlying the compensation expense for both types of incentive units were estimated using a Monte Carlo simulation. The Monte Carlo simulation projected the fair value per incentive unit using the expected volatility, the risk free rate and other variables. The service period, which began on the date of grant and continues through final distribution, has been estimated primarily based upon our assumptions regarding the timing and size of secondary offerings of shares of our common stock by NGP Holdings and/or other liquidity events. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the non-cash compensation expense recognized. For additional information see Note 13 in the notes to the consolidated financial statements under Item 8 of this Annual Report. Non-cash compensation expenses related to the incentive units is included in incentive unit expense within the consolidated statement of operations.

Income Taxes

We are a corporation under the Internal Revenue Code subject to federal income tax at a statutory rate of 35% of pretax earnings and, as such, our future income taxes will be dependent upon our future taxable income. We did not report any income tax benefit or expense for periods prior to the consummation of our IPO in January 2014 because Rice Drilling B, our accounting predecessor, is a limited liability company that was not and currently is not subject to federal income tax. The reorganization of our business in connection with the closing of the IPO, such that it is now held by a corporation subject to federal income tax, required the recognition of a deferred tax asset or liability for the initial temporary differences at the time of the IPO. The resulting deferred tax liability of approximately \$162.3 million was recorded in equity at the date of the completion of the IPO as it represents a transaction among shareholders. Additionally, we have presented pro forma earnings per share ("EPS") for the year ended December 31, 2014 assuming a statutory rate as disclosed in the Consolidated Statements of Operations was applied for the full year ended December 31, 2014.

We follow ASC 740-10-25, which requires the use of a two-step approach for recognizing and measuring tax benefits taken or expected to be taken in a tax return and disclosures regarding uncertainties in income tax positions. Only tax positions that meet the more likely than not recognition threshold are recognized. We did not have any uncertain tax positions as of December 31, 2014.

Income taxes are accounted for under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which differences are expected to be recovered or settled pursuant to the provisions of ASC 740-Income Taxes. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

We will record a valuation allowance if it is deemed more likely than not that all or a portion of its deferred income tax assets will not be realized. In addition, income tax rules and regulations are subject to interpretation and the application of those rules and regulations require judgment by us and may be challenged by the taxation authorities.

Business Combinations

For acquisitions of working interests that are accounted for as business combinations, the results of operations are included in the consolidated statement of operations from the date of acquisition. Purchase prices are allocated to assets acquired based on their estimated fair values at the time of acquisition. Fair value is the price that would be received to sell an asset or would be paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value. The fair value

of natural gas properties is determined using a risk-adjusted after-tax discounted cash flow analysis based upon significant inputs including gas prices; projections of estimated quantities of natural gas reserves, including those classified as proved, probable and possible; projections of future rates of production; timing and amount of future development and operating costs; projected reserve recovery factors; and weighted average cost of capital.

New Accounting Pronouncements

In May 2014, the FASB issued ASU, No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," or ASU No. 2014-09. The FASB created Topic 606 which supersedes the revenue recognition requirements in Topic 605, "Revenue Recognition," and most industry-specific guidance throughout the Industry Topics of the Codification. ASU 2014-09 will enhance comparability of revenue recognition practices across entities, industries and capital markets compared to existing guidance. Additionally, ASU 2014-09 will reduce the number of requirements to which an entity must consider in recognizing revenue as this update will replace multiple locations for guidance. The FASB and International Accounting Standards Board initiated this joint project to clarify the principles for recognizing revenue and to develop a common revenue standard for both U.S. GAAP and International Financial Reporting Standards. ASU 2014-09 is effective for fiscal and interim periods beginning after December 15, 2016 and should be applied retrospectively. Early adoption of this standard is not permitted. The Company is currently evaluating the impact of the provisions of ASU 2014-09.

In February 2015, the FASB issued ASU, 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." ASU 2015-02 affects reporting entities that are required to evaluate whether they should consolidate certain legal entities. ASU 2015-02 is effective for periods beginning after December 15, 2015 with early adoption permitted. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its consolidated financial statements.

Off-Balance Sheet Arrangements

As of December 31, 2014, we did not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See Note 9 to our consolidated financial statements for a description of our commitments and contingencies.

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 risk. The term “market risk” refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Price Risk and Hedges

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

To mitigate some of the potential negative impact on our cash flow caused by changes in commodity prices, we enter into financial commodity swap contracts to receive fixed prices for a portion of our natural gas, NGLs, and oil production to mitigate the potential negative impact on our cash flow.

Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas, NGLs, and oil price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. These contracts may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, cashless price collars that set a floor and ceiling price for the hedged production, or basis differential swaps. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference.

By removing price volatility from a portion of our expected natural gas production through December 2017, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the hedge prices.

Interest Rate Risks

As of December 31, 2014, we had zero borrowings and approximately \$66.8 million in letters of credit outstanding under our Senior Secured Revolving Credit Facility. As of December 31, 2014, we had availability under the borrowing base of our Senior Secured Revolving Credit Facility of approximately \$483.2 million and the borrowing base was \$550.0 million. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized.

As of December 31, 2014, Rice Midstream OpCo had no borrowings outstanding and no letters of credit under the RMP Revolving Credit Facility. Rice Midstream OpCo has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans will bear interest at a rate per annum equal to the applicable LIBOR Rate plus an applicable margin ranging from 175 to 275 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 75 to 175 basis points, depending on the leverage ratio then in effect.

As of December 31, 2014, Rice Midstream Holdings had no borrowings outstanding and no letters of credit under the Midstream Holdings Revolving Credit Facility. Rice Midstream Holdings has a choice of borrowing in Eurodollars or

at the base rate. Eurodollar loans bear interest at a rate per annum equal to the applicable LIBOR Rate plus an applicable margin ranging from 225 to 300 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 125 to 200 basis points, depending on the leverage ratio then in effect.

As of December 31, 2014, we did not have any derivatives in place to mitigate the effects of interest rate risk. We may implement an interest rate hedging strategy in the future.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through joint interest receivables (\$125.3 million in receivables as of December 31, 2014) and the sale of our natural gas production (\$72.2 million in receivables as of December 31, 2014), which we market to multiple natural gas marketing companies. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with one natural gas marketing company. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm
The Board of Directors and Shareholders of
Rice Energy Inc.

We have audited the accompanying consolidated balance sheets of Rice Energy Inc. (the Company) as of December 31, 2014 and 2013, and the related consolidated statements of operations, cash flows and equity 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Rice Energy Inc. at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania

March 13, 2015

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Rice Energy Inc.
Consolidated Balance Sheets

(in thousands)	December 31,	
	2014	2013
Assets		
Current assets:		
Cash	\$256,130	\$31,612
Restricted cash	—	8,268
Accounts receivable	199,900	31,765
Receivable from affiliate	88	2,244
Deposits	693	601
Prepaid expenses and other	2,646	262
Derivative assets	133,034	—
Total current assets	592,491	74,752
Investments in joint ventures	—	49,814
Gas collateral account	3,995	3,700
Property, plant and equipment, net	2,461,331	734,331
Deferred financing costs, net	25,103	12,292
Goodwill	334,050	—
Intangible assets, net	47,791	—
Derivative assets	63,188	4,921
Total assets	\$3,527,949	\$879,810
Liabilities and stockholders' equity		
Current liabilities:		
Current portion of long-term debt	\$680	\$20,120
Accounts payable	152,329	51,219
Royalties payable	37,172	9,393
Accrued capital expenditures	108,290	16,753
Leasehold payable	30,702	18,606
Deferred tax liabilities	54,688	—
Other accrued liabilities	52,814	16,847
Total current liabilities	436,675	132,938
Long-term liabilities:		
Long-term debt	900,000	406,822
Leasehold payable	4,279	1,675
Deferred tax liabilities	209,218	—
Restricted units	—	36,306
Other long-term liabilities	12,609	3,422
Total liabilities	1,562,781	581,163
Stockholders' equity:		
Common stock, \$0.01 par value; authorized - 650,000,000 shares; issued and outstanding 136,280,766 shares and 88,000,000 shares, respectively	1,363	880
Preferred stock, \$0.01 par value; authorized - 50,000,000 shares; none issued	—	—
Additional paid in capital	1,368,001	362,875
Accumulated earnings (deficit)	153,346	(65,108)

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Stockholders' equity before noncontrolling interest	1,522,710	298,647
Noncontrolling interests in consolidated subsidiaries	442,458	—
Total liabilities and stockholders' equity	\$3,527,949	\$879,810

The accompanying notes are an integral part of these Consolidated Financial Statements.

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Rice Energy Inc.
Consolidated Statements of Operations

(in thousands, except share data)	Years Ended December 31,			
	2014	2013	2012	
Operating revenues:				
Natural gas, oil and natural gas liquids (NGL) sales	\$359,201	\$87,847	\$26,743	
Firm transportation sales, net	26,237	—	—	
Other revenue	5,504	840	457	
Total operating revenues	390,942	88,687	27,200	
Operating expenses:				
Lease operating	24,971	8,309	3,688	
Gathering, compression and transportation	40,225	9,774	3,754	
Production taxes and impact fees	4,647	1,629	1,382	
Exploration	4,225	9,951	3,275	
Incentive unit expense	105,961	—	—	
Restricted unit expense	—	32,906	—	
Stock compensation expense	5,553	—	—	
General and administrative	56,017	16,953	7,599	
Depreciation, depletion and amortization	156,270	32,815	14,149	
Acquisition expense	2,339	—	—	
Amortization of intangible assets	1,156	—	—	
Write-down of abandoned leases	—	—	2,253	
Loss from sale of interest in gas properties	—	4,230	—	
Total operating expenses	401,364	116,567	36,100	
Operating loss	(10,422) (27,880) (8,900)
Interest expense	(50,191) (17,915) (3,487)
Gain on purchase of Marcellus joint venture	203,579	—	—	
Other income (loss)	893	(440) 112	
Gain (loss) on derivative instruments	186,477	6,891	(1,381)
Amortization of deferred financing costs	(2,495) (5,230) (7,220)
Loss on extinguishment of debt	(7,654) (10,622) —	
Write-off of deferred financing costs	(6,896) —	—	
Equity in income (loss) of joint ventures	(2,656) 19,420	1,532	
Income (loss) before income taxes	310,635	(35,776) (19,344)
Income tax expense	(91,600) —	—	
Net income (loss)	219,035	(35,776) (19,344)
Less: Net income attributable to noncontrolling interests	(581) —	—	
Net income (loss) attributable to Rice Energy Inc.	\$218,454	\$(35,776) \$(19,344)
Weighted average number of shares of common stock - basic	128,151,171	80,441,905	58,231,763	
Weighted average number of shares of common stock - diluted	128,225,155	80,441,905	58,231,763	
Earnings (loss) per share—basic	\$1.70	\$(0.44) \$(0.33)
Earnings (loss) per share—diluted	\$1.70	\$(0.44) \$(0.33)
Pro forma income tax benefit (unaudited)	\$5,560			
Pro forma net income (unaudited)	\$224,596			
Earnings per share—basic (unaudited)	\$1.75			
Earnings per share—diluted (unaudited)	\$1.75			

The accompanying notes are an integral part of these Consolidated Financial Statements.

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Rice Energy Inc.
Consolidated Statements of Cash Flows

(in thousands)	Years Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net income (loss)	\$219,035	\$(35,776)	\$(19,344)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	156,270	32,815	14,149
Amortization of deferred financing costs, loss on extinguishment of debt and other	10,149	5,230	7,220
Amortization of intangibles	1,156	—	—
Incentive unit expense	105,961	—	—
Write-off of deferred financing costs	6,896	—	—
Loss (gain) from sale of interest in gas properties	—	4,230	—
Restricted unit expense	—	32,906	—
Write-off of unsuccessful exploratory well costs	2,211	8,143	—
Stock compensation expense	5,553	—	—
Derivative instruments fair value (gain) loss	(186,477)	(6,891)	1,381
Cash payments for settled derivatives	(18,784)	676	879
Deferred income tax expense	87,639	—	—
Fair value gain on purchase of Marcellus joint venture	(203,579)	—	—
Equity in (income) loss of joint ventures	2,656	(19,420)	(1,532)
Write-down of abandoned leases and other leasehold costs	—	—	2,253
Changes in operating assets and liabilities:			
(Increase) in accounts receivable and receivable from affiliate	(151,427)	(7,573)	(12,231)
(Increase) decrease in prepaid expenses and other assets	(1,996)	102	(4,349)
Increase (decrease) in accounts payable	4,661	2,273	(30)
Increase in accrued liabilities and other	25,280	9,525	7,815
Royalties payable	19,871	7,432	775
Net cash provided by (used in) operating activities	85,075	33,672	(3,014)
Cash flows from investing activities:			
Capital expenditures for natural gas properties	(959,280)	(463,128)	(109,149)
Investment in joint ventures	—	—	(9,957)
Acquisition of Marcellus joint venture, net of cash acquired	(82,766)	—	—
Acquisition of Momentum assets	(111,847)	—	—
Acquisition of Greene County assets	(329,469)	—	—
Capital expenditures for property and equipment	(10,994)	(2,259)	(867)
Proceeds from sale of interest in gas properties	12,891	6,792	—
Net cash used in investing activities	(1,481,465)	(458,595)	(119,973)
Cash flows from financing activities:			
Proceeds from borrowings	1,090,000	435,500	44,361
Repayments of debt obligations	(689,873)	(160,760)	(10,152)
Restricted cash for convertible debt	8,268	(8,268)	—
Debt issuance costs	(24,543)	(12,194)	(1,913)
Common stock issuance	—	195,977	96,782
Repurchase of common stock	—	(2,267)	(1,133)

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Proceeds from conversion of warrants	1,975	—	—
Proceeds from issuance of common stock sold in our IPO, net of offering costs	597,088	—	—
Proceeds from issuance of common stock sold in August 2014 Equity Offering, net of offering costs	196,254	—	—
Proceeds from issuance of common units sold in RMP IPO, net of offering costs	441,739	—	—
Return of capital	—	—	(800)
Net cash provided by financing activities	1,620,908	447,988	127,145
Net increase in cash	224,518	23,065	4,158
Cash at the beginning of the year	31,612	8,547	4,389
Cash at the end of the year	\$256,130	\$31,612	\$8,547

Rice Energy Inc.

Consolidated Statements of Cash Flows - (Continued)

(in thousands)	Years Ended December 31,		
	2014	2013	2012
Supplemental disclosure of noncash investing and financing activities			
Capital expenditures for natural gas properties financed by accounts payable	\$ 144,053	\$ 48,615	\$ 18,083
Capital expenditures for natural gas properties financed by other accrued liabilities	108,290	16,753	2,359
Natural gas properties financed through borrowings	—	—	18,328
Accretion of debt discount	822	2,099	—
Capital expenditures for property, office furniture and equipment funded by capital lease borrowings	2,623	1,557	419
Natural gas properties financed through deferred payment obligations	34,984	20,281	3,577
Natural gas properties financed through other liabilities	—	—	8,261
Recognition of legal liability for asset retirement obligations	7,171	583	382
Application of advances from joint interest owners	(7,304)	(10,415)	—
Conversion of related-party note payable to equity	—	255	11,332

The accompanying notes are an integral part of these Consolidated Financial Statements.

Rice Energy Inc.
Statements of Consolidated Equity

(in thousands)	Common Stock (\$0.01 par)	Additional Paid-In Capital	Accumulated Deficit	Total
Balance, January 1, 2012	\$406	\$56,403	\$(9,988)) \$46,821
Capital contributions, net	192	99,990	—	100,182
Return of capital	(1) (799) —	(800
Conversion of related-party notes payable	25	11,307	—	11,332
Consolidated net loss	—	—	(19,344)) (19,344
Balance, December 31, 2012	\$622	\$166,901	\$(29,332)) \$138,191
Capital contributions, net	258	195,974	—	196,232
Consolidated net loss	—	—	(35,776)) (35,776
Balance, December 31, 2013	\$880	\$362,875	\$(65,108)) \$298,647

(in thousands)	Common Stock (\$0.01 par)	Additional Paid-In Capital	Accumulated (Deficit) Earnings	Stockholders Equity before Non-controlling Interest	Non-Controlling Interest	Total Equity
Balance, January 1, 2014	\$880	\$362,875	\$(65,108)) \$ 298,647	\$ —	298,647
Shares of common stock issued in initial public offering, net of offering costs	300	593,113	—	593,413	—	593,413
Shares of common stock issued in purchase of Marcellus joint venture	95	221,905	—	222,000	—	222,000
Conversion of restricted units into shares of common stock at our IPO	—	36,306	—	36,306	—	36,306
Conversion of convertible debentures into shares of common stock after our IPO	6	6,599	—	6,605	—	6,605
Conversion of warrants into shares of common stock after our IPO	7	1,968	—	1,975	—	1,975
Shares of common stock issued in August 2014 Equity Offering, net of offering costs	75	196,179	—	196,254	—	196,254
Shares of common units issued in RMP IPO, net of offering costs	—	—	—	—	441,739	441,739
Incentive unit compensation	—	105,961	—	105,961	—	105,961
Stock compensation	—	5,415	—	5,415	138	5,553
Tax impact of our IPO and corporate reorganization	—	(162,320)	—	(162,320)	—	(162,320)
Net income	—	—	218,454	218,454	581	219,035
Balance, December 31, 2014	\$1,363	\$1,368,001	\$153,346	\$1,522,710	\$442,458	\$1,965,168

The accompanying notes are an integral part of these Consolidated Financial Statements.

Rice Energy Inc.

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies and Related Matters

Organization, Operations and Principals of Consolidation

The accompanying consolidated financial statements of Rice Energy Inc. (the “Company,” “we,” “our,” and “us”) have been prepared by the Company’s management in accordance with generally accepted accounting principles in the United States (“GAAP”) for financial information and applicable rules and regulations promulgated under the Exchange Act. The consolidated financial statements of the Company include the accounts of its wholly-owned subsidiaries. Rice Midstream Holdings LLC, a wholly-owned subsidiary of the Company (“Rice Midstream Holdings”) owns a 50.0% interest in Rice Midstream Partners LP, a subsidiary of the Company, (“the Partnership”). The financial results of the Partnership are consolidated and the remaining 50.0% interest in the Partnership is reflected as noncontrolling interest in the consolidated financial statements. All intercompany transactions have been eliminated in consolidation.

Corporate Reorganization and Initial Public Offering

On January 29, 2014, we completed our initial public offering (our “IPO”) of 50,000,000 shares of our \$0.01 par value common stock, which included 30,000,000 shares sold by us, 14,000,000 shares sold by NGP Rice Holdings, LLC (“NGP Holdings”), the selling stockholder in our IPO, and 6,000,000 shares sold subject to an option granted to the underwriters by the selling stockholder.

The net proceeds of our IPO, based on the public offering price of \$21.00 per share, were approximately \$992.6 million, which resulted in net proceeds to us of \$593.6 million after deducting expenses and underwriting discounts and commissions of approximately \$36.4 million and the net proceeds to the selling stockholder of approximately \$399.0 million after deducting expenses and underwriting discounts of approximately \$21.0 million. We did not receive any proceeds from the sale of the shares by the selling stockholder. A portion of the net proceeds from our IPO were used to repay all outstanding borrowings under the revolving credit facility of Alpha Shale Resources, LP and its general partner, Alpha Shale Holdings, LLC (collectively, our “Marcellus joint venture”), to make a \$100.0 million payment to Foundation PA Coal Company, LLC, a wholly-owned indirect subsidiary of Alpha Natural Resources, Inc. (“Alpha Holdings”) in partial consideration for our acquisition of Alpha Holdings’ 50% interest in our Marcellus joint venture (the “Marcellus JV Buy-In”) and to repay all outstanding borrowings under our Senior Secured Revolving Credit Facility (as defined below). We used the remainder of the net proceeds from our IPO to fund a portion of our capital expenditure plan.

A corporate reorganization occurred concurrently with the completion of our IPO on January 29, 2014. As a part of this corporate reorganization, we acquired all of the outstanding membership interests in Rice Energy Appalachia LLC (“Rice Appalachia”) and Rice Drilling B LLC (“Rice Drilling B”) (other than those already held by Rice Appalachia) in exchange for shares of our common stock. Our Exploration and Production segment continues to be conducted through Rice Drilling B, now a wholly-owned subsidiary. This reorganization constituted a common control transaction and the accompanying consolidated financial statements are presented as though this reorganization had occurred for the earliest period presented.

As of January 29, 2014, upon (a) the completion of our IPO, (b) the issuance of (i) 43,452,550 shares of common stock to NGP Holdings, (ii) 20,300,923 shares of common stock to Rice Holdings, (iii) 2,356,844 shares of common stock to Daniel J. Rice III, (iv) 20,000,000 shares of common stock to Rice Partners, (v) 160,831 shares of common stock to the persons holding incentive units representing interests in Rice Appalachia and (vi) 1,728,852 shares of common stock to the members of Rice Drilling B (other than Rice Appalachia), each of which were issued by us in connection with the closing of our IPO, and (c) the issuance of 9,523,810 shares of common stock to Alpha Holdings in connection with the completion of the Marcellus JV Buy-In, we had 127,523,810 shares of common stock outstanding.

Rice Midstream Partners Initial Public Offering

On December 22, 2014, the Partnership completed its initial public offering (the “RMP IPO”) of 28,750,000 common units representing limited partner interests (the “Common Units”), which included 3,750,000 Common Units sold subject to an option granted to the underwriters. The net proceeds of the RMP IPO, based on the public offering price of \$16.50 per Common Unit, were approximately \$441.7 million, after deducting underwriting discounts, commissions, structuring fees and expenses. See Note 6 for further discussion of the RMP IPO.

Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles 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 dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates and changes in these estimates are recorded when known.

Revenue Recognition

Sales of natural gas, NGLs and oil are recognized when the products 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. Natural gas is sold by the Company under contracts with the Company's natural gas marketers. Pricing provisions are tied to the Platts Gas Daily market prices. Some transportation costs incurred by the Company are marketed for resale and are not incurred to transport gas produced by the Company's Exploration and Production segment. These transportation costs are reflected as a deduction from the related firm transportation sales revenue at the time the transportation is provided to the customer.

Cash

The Company maintains cash at financial institutions which may at times exceed federally insured amounts and which may at times significantly exceed consolidated balance sheet amounts due to outstanding checks. The Company has no other accounts that are considered cash equivalents.

Accounts Receivable

Accounts receivable are primarily from the Company's joint interest partners and natural gas marketers. The Company extends credit to parties in the normal course of business based upon management's assessment of their creditworthiness. A valuation allowance is provided for those accounts for which collection is estimated as doubtful; uncollectible accounts are written off and charged against the allowance. In estimating the allowance, management considers, among other things, how recently and how frequently payments have been received and the financial position of the party. There was no allowance recorded for any of the periods presented in the consolidated financial statements. Accounts receivable as of December 31, 2014 and 2013 are detailed below.

(in thousands)	December 31,	
	2014	2013
Natural gas sales	\$72,206	\$16,534
Joint interest	125,300	6,391
Other	2,394	8,840
Total accounts receivable	\$199,900	\$31,765

Noncontrolling Interest

Noncontrolling interests represent third-party equity ownership of the Partnership and are presented as a component of equity in the consolidated balance sheets. In the consolidated statements of operations, noncontrolling interest reflects the allocation of earnings to the third-party investors. The Company consolidates the results of the Partnership as the Company owns a 50.0% equity interest in the Partnership and controls the Partnership through its ownership of the general partner. See Note 6 for further discussion of noncontrolling interests related to the Partnership.

Property, Plant and Equipment

The Company uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that result in proved reserves, are capitalized. Costs to drill exploratory wells that do not identify proved reserves as well as geological and geophysical costs and costs of carrying and retaining unproved properties are expensed.

Long-lived assets to be held and used or disposed of other than by sale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets

to be held and used or disposed other than by sale are recognized based on the fair value of the asset. Long-lived assets to be disposed of by sale are reported at the lower of their carrying amount or fair value less selling costs. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Unproved oil and gas properties had a net book value of \$1,015.4 million and \$426.8 million at December 31, 2014 and December 31, 2013, respectively. Capitalized costs of producing oil and gas properties and support equipment directly related to such properties, after considering estimated residual salvage values, are depreciated and depleted by the units of production method. Support equipment and other property and equipment not directly related to oil and gas properties are depreciated over their estimated useful lives.

Midstream property and other equipment are recorded at cost and are being depreciated over estimated useful lives of fifteen to sixty years on a straight-line basis. Support equipment and other property and equipment are recorded at cost and are being depreciated over estimated useful lives of three to forty years on a straight-line basis.

Management's estimates of proved reserves are based on quantities of oil and natural gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic conditions. External engineers prepare the annual reserve and economic evaluation of all properties on a well-by-well basis. Additionally, the Company adjusts oil and natural gas reserves for major well rework or abandonment during the year as needed. The process of estimating and evaluating oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering, and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates represent the Company's most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect the Company's depreciation, depletion, and amortization expense, a change in the Company's estimated reserves could have a material effect on the Company's operating results.

Upon the sale of an entire interest in an unproved property for cash, a gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained unless the proceeds received are in excess of the cost basis which would result in gain on sale.

Interest

The Company capitalizes interest on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use. Upon completion of construction of the asset, the associated capitalized interest costs are included within our asset base and depleted accordingly. The following table summarizes the components of the Company's interest incurred for the years ended December 31, 2014, 2013 and 2012:

(in thousands)	2014	2013	2012
Interest incurred:			
Interest capitalized	\$905	\$8,034	\$7,695
Interest expensed	50,191	17,915	3,487
Total incurred	\$51,096	\$25,949	\$11,182

Goodwill and Intangible Assets

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment at least annually, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If the carrying amount of the goodwill of the identifiable assets exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. No impairments for such assets have been recorded in any of the periods presented.

Intangible assets are comprised of customer contracts acquired in our April 2014 acquisition of certain gas gathering assets in eastern Washington and Greene Counties, Pennsylvania (the "Momentum Acquisition") based upon the estimated fair value of the assets at the acquisition date. The customer contracts are amortized over 30 years using a

straight-line method, and amortization expense recorded in the consolidated statements of operations for the year ended December 31, 2014 was \$1.2

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million. The estimated annual amortization expense over the next five years is as follows: 2015 - \$1.6 million, 2016 - \$1.6 million, 2017 - \$1.6 million, 2018 - \$1.6 million and 2019 - \$1.6 million.

Goodwill and intangible assets as of December 31, 2014 are detailed below.

(in thousands)	December 31, 2014		
	Gross	Accumulated Amortization	Net
Goodwill	\$334,050	—	\$334,050
Intangible assets	\$48,947	(1,156) \$47,791
Deferred Financing Costs			

Deferred financing costs are amortized on a straight-line basis, which approximates the interest method, over the term of the related agreement. Accumulated amortization was \$3.5 million and \$14.3 million at December 31, 2014 and 2013 respectively. Amortization expense was \$2.5 million, \$5.2 million, and \$7.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. The annual amortization of deferred financing costs for years subsequent to December 31, 2014, is expected to be approximately \$4.1 million in 2015, \$4.1 million in 2016, \$4.1 million in 2017, \$4.1 million in 2018 and \$8.7 million in 2019 and thereafter.

Asset Retirement Obligations

The Company records the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The Company's retirement obligations relate to the abandonment of oil and gas producing facilities and include costs to reclaim drilling sites and dismantle and relocate or dispose of gathering systems, wells and related structures. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining lives of those wells based on reserve estimates.

When a new liability is recorded, the Company capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the capitalized cost is depreciated over the units of production basis.

Income Taxes

We are a corporation under the Internal Revenue Code subject to federal income tax at a statutory rate of 35% of pretax earnings. We did not report any income tax benefit or expense for periods prior to the consummation of our IPO in January 2014 because Rice Drilling B, our accounting predecessor, is a limited liability company that was not and currently is not subject to federal income tax. The reorganization of our business in connection with the closing of our IPO, such that it is now held by a corporation subject to federal income tax, required the recognition of a deferred tax asset or liability for the initial temporary differences at the time of our IPO. The resulting deferred tax liability of approximately \$162.3 million was recorded in equity at the date of the completion of our IPO as it represents a transaction among shareholders. Additionally, we have presented pro forma earnings per share ("EPS") for the year ended December 31, 2014 assuming a statutory rate as disclosed in the accompanying consolidated statements of operations was applied for the full year ended December 31, 2014.

The Company follows ASC 740-10-25, which requires the use of a two-step approach for recognizing and measuring tax benefits taken or expected to be taken in a tax return and disclosures regarding uncertainties in income tax positions. Only tax positions that meet the more likely than not recognition threshold are recognized. Based on management's analysis, the Company did not have any uncertain tax positions as of December 31, 2014.

Income taxes are accounted for under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which differences are expected to be recovered or settled pursuant to the provisions of ASC 740-Income Taxes. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

The Company will record a valuation allowance if it is deemed more likely than not that all or a portion of its deferred income tax assets will not be realized. In addition, income tax rules and regulations are subject to interpretation and the application of those rules and regulations requires judgment by us and may be challenged by the taxation authorities.

Reclassifications

Certain reclassifications have been made to prior periods' financial information related to gathering revenues, post production costs, restricted unit liability and asset retirement obligations to conform to the 2014 presentation.

Correction of Errors

The Company's net income for the year ended December 31, 2012 included expense of approximately \$1.7 million that related to prior periods. These corrections resulted in additional exploration expense of approximately \$1.1 million, lease operating expense of \$0.5 million, and other expense of \$0.1 million recorded in 2012. These errors were not material to prior periods, individually or in the aggregate, and were not material to the 2012 period. These errors did not impact debt covenant compliance nor distort operating results. Therefore, these items were corrected in fiscal 2012.

2. Property, Plant and Equipment

The Company's property, plant and equipment are as follows:

(in thousands)	December 31,	
	2014	2013
Oil and gas producing properties	\$2,181,880	\$704,028
Accumulated depreciation	(201,608)	(50,710)
Oil and gas producing properties, net	1,980,272	653,318
Midstream property and equipment	467,956	76,644
Accumulated depreciation	(4,038)	(1,602)
Midstream property and equipment, net	463,918	75,042
Other property and equipment	21,376	7,526
Accumulated depreciation	(4,235)	(1,555)
Other property and equipment, net	17,141	5,971
Property, plant and equipment, net	\$2,461,331	\$734,331

3. Long-Term Debt

Long-term debt consists of the following as of December 31, 2014 and 2013:

(in thousands)	December 31,	
	2014	2013
Long-term Debt		
Senior Notes Due 2022 ^(a)	\$900,000	\$—
Senior Secured Revolving Credit Facility ^(b)	—	115,000
Second Lien Term Loan Facility ^(c)	—	293,821
Debentures ^(d)	—	6,890
NPI Note	—	8,028
Other	680	3,203
Total debt	\$900,680	\$426,942
Less current portion	680	20,120
Long-term debt	\$900,000	\$406,822

6.25% Senior Notes Due 2022 (a)

On April 25, 2014, the Company issued \$900.0 million in aggregate principal amount of 6.25% senior notes due 2022 (the "Notes") in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act, which resulted in

net proceeds of \$882.7 million, after deducting expenses and the initial purchasers' discounts of approximately \$17.3 million. The Company used \$301.8 million of the net proceeds to repay and retire the Second Lien Term Loan Facility (defined below) and used the remainder to fund a portion of the Company's 2014 capital expenditure program. The Notes will mature on May 1, 2022, and interest is payable on the Notes on each May 1 and November 1. At any time prior to May 1, 2017, the Company may redeem up to 35% of the Notes at a redemption price of 106.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to May 1, 2017, the Company may redeem some or all of the notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. Upon the occurrence of a Change of Control (as defined in the indenture governing the notes (the "Indenture"), unless the Company has given notice to redeem the Notes, the holders of the Notes will have the right to require the Company to repurchase all or a portion of the Notes at a price equal to 101% of the aggregate principal amount of the Notes, plus any accrued and unpaid interest to the date of purchase. On or after May 1, 2017, the Company may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104.688% for the twelve-month period beginning on May 1, 2017, 103.125% for the twelve-month period beginning May 1, 2018, 101.563% for the twelve-month period beginning on May 1, 2019 and 100.000% beginning on May 1, 2020, plus accrued and unpaid interest to the redemption date.

The Notes are the Company's senior unsecured obligations, rank equally in right of payment with all of the Company's existing and future senior debt, and will rank senior in right of payment to all of the Company's future subordinated debt. The Notes will be effectively subordinated to all of the Company's existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

The notes are jointly and severally, fully and unconditionally, guaranteed by any of the Company's restricted subsidiaries (such subsidiaries, the "Guarantors") that guaranteed the Company's obligations under a Credit Facility (as defined in the Indenture). Guarantees of the Notes will be released under certain circumstances, including:

in connection with any sale or other disposition of all or substantially all of the assets of that Guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary (as defined in the Indenture) of the Company;

in connection with any sale or other disposition of the capital stock of that Guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, such that, immediately after giving effect to such transaction, such Guarantor would no longer constitute a subsidiary of the Company;

if the Company designates any Restricted Subsidiary that is a Guarantor to be an unrestricted subsidiary in accordance with the Indenture;

upon legal defeasance or satisfaction and discharge of the Indenture; or

if such Guarantor ceases to guarantee any other indebtedness of the Company or a Guarantor under a credit facility, provided no Event of Default (as defined in the Indenture) has occurred and is continuing.

The Indenture restricts the Company's ability and the ability of its restricted subsidiaries to: (i) incur or guarantee additional debt or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated debt; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; (vii) transfer and sell assets; and (viii) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and the Company and its restricted subsidiaries will cease to be subject to such covenants.

The Indenture contains customary events of default, including:

default in any payment of interest on any Note when due, continued for 30 days;

default in the payment of principal of or premium, if any, on any Note when due;

failure by the Company to comply with its other obligations under the Indenture, in certain cases subject to notice and grace periods;

payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries (as defined in the Indenture) in the aggregate principal amount of \$25.0 million or more;

certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the Indenture) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;

failure by the Company or Restricted Subsidiary to pay certain final judgments aggregating in excess of \$25.0 million within 60 days; and

any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

In connection with the issuance and sale of the Notes, the Company and the Guarantors named therein entered into a registration rights agreement with the Initial Purchasers, dated April 25, 2014. Pursuant to the registration rights agreement, the Company completed an exchange of the Notes for registered notes that have substantially identical terms as the Notes.

Senior Secured Revolving Credit Facility (b)

On April 25, 2013, Rice Drilling B entered into a Senior Secured Revolving Credit Facility (the "Senior Secured Revolving Credit Facility") with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders with a maximum credit amount of \$500.0 million and a sublimit for letters of credit of \$10.0 million. Concurrently with the closing of our IPO, on January 29, 2014, Rice Drilling B amended the credit agreement governing the Senior Secured Revolving Credit Facility to, among other things, allow for the corporate reorganization that was completed simultaneously with the closing of our IPO, add the Company as a guarantor, increase the maximum commitment amount to \$1.5 billion and lower the interest rate on amounts borrowed under the Senior Secured Revolving Credit Facility. The Company used a portion of the net proceeds of the IPO to repay \$115.0 million of borrowings under the Senior Secured Revolving Credit Facility. After giving effect to the amendment, the borrowing base under the Senior Secured Revolving Credit Facility was increased to \$350.0 million as a result of the Marcellus JV Buy-In.

In April 2014, concurrently with the Senior Notes Offering, the Company, as borrower, and Rice Drilling B, as predecessor borrower, amended and restated the credit agreement governing the Senior Secured Revolving Credit Facility (the "Amended Credit Agreement") to, among other things, assign all of the rights and obligations of Rice Drilling B as borrower under the Senior Secured Revolving Credit Facility to the Company. Furthermore, the Amended Credit Agreement (i) allowed for the issuance of the Notes described above and (ii) provided that the Company did not incur an immediate reduction in the borrowing base under the Senior Secured Revolving Credit Facility as a result of the issuance of the Notes. As such, the borrowing base under the Amended Credit Agreement immediately following the issuance of the Notes remained at \$350.0 million. The Amended Credit Agreement also extended the maturity date of the Senior Secured Revolving Credit Facility from April 25, 2018 to January 29, 2019. The amount available to be borrowed under the Amended Credit Agreement is subject to a semi-annual borrowing base redetermination that depends on, among other factors, the volumes of the Company's proved oil and gas reserves. As of December 31, 2014, the borrowing base was \$550.0 million and the sublimit for letters of credit was \$100.0 million. The Company had zero borrowings outstanding and \$66.8 million in letters of credit outstanding under its Amended Credit Agreement as of December 31, 2014, resulting in availability of \$483.2 million. The next redetermination is scheduled for April 2015 based on the redetermination criteria as of January 1, 2015.

Eurodollar loans under the Senior Secured Revolving Credit Facility bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of borrowing base utilized.

The Amended Credit Agreement is secured by liens on at least 80% of the proved oil and gas reserves of the Company and its subsidiaries (other than any subsidiary that is designated as an unrestricted subsidiary, including Rice Midstream Holdings and its subsidiaries), as well as significant unproved acreage and substantially all of the personal property of the Company and such restricted subsidiaries, and the Company's obligations under the Amended Credit Agreement are guaranteed by such restricted subsidiaries. The Amended Credit Agreement contains restrictive covenants that limit the ability of the Company and its restricted subsidiaries to, among other things:

incur additional indebtedness;
sell assets;
make loans to others;

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- make investments;
- enter into mergers;
- make or declare dividends;
- hedge future production or interest rates;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Amended Credit Agreement also requires the Company to maintain certain financial ratios, which are measured at the end of each calendar quarter:

a current ratio, which is the ratio of consolidated current assets (including unused commitments under the Amended Credit Agreement and excluding non-cash derivative assets) to consolidated current liabilities (excluding current maturities under the Amended Credit Agreement and non-cash derivative liabilities), of not less than 1.0 to 1.0; and a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX (as such term is defined in the Amended Credit Agreement) based on the trailing 12 month period to consolidated interest expense, of not less than 2.5 to 1.0.

The Company was in compliance with such covenants and ratios effective as of December 31, 2014.

Midstream Holdings Revolving Credit Facility

On December 22, 2014, Rice Midstream Holdings LLC entered into a revolving credit facility (“Midstream Holdings Revolving Credit Facility”) with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders with a maximum credit amount of \$300.0 million and a sublimit for letters of credit of \$25.0 million. As of December 31, 2014, Rice Midstream Holdings had no borrowings outstanding and no letters of credit under this facility. The credit facility is available to fund working capital requirements and capital expenditures and to purchase assets and matures on December 22, 2019. Rice Olympus Midstream LLC, Rice Water Services (OH) LLC and Rice Water Services (PA) LLC are the guarantors of the obligations under the credit facility.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Rice Midstream Holdings has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the applicable LIBOR Rate plus an applicable margin ranging from 225 to 300 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 125 to 200 basis points, depending on the leverage ratio then in effect. Rice Midstream Holdings will also pay a commitment fee based on the undrawn commitment amount ranging from 37.5 to 50 basis points.

The Midstream Holdings Revolving Credit Facility is secured by mortgages and other security interests on substantially all of the properties of, and guarantees from, Rice Midstream Holdings and its restricted subsidiaries (which do not include the Partnership, Rice Midstream Management LLC, a Delaware limited liability company and general partner of the Partnership, or the Company and its subsidiaries other than Rice Midstream Holdings).

The Midstream Holdings Revolving Credit Facility limits the ability of Rice Midstream Holdings and its restricted subsidiaries to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
 - merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The Midstream Holdings Revolving Credit Facility also requires Rice Midstream Holdings to maintain the following financial ratios:

an interest coverage ratio, which is the ratio of Rice Midstream Holding's consolidated EBITDA (as defined within the Midstream Holdings Revolving Credit Facility) to its consolidated current interest expense of at least 2.50 to 1.0 at the end of each fiscal quarter; and

a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 4.25 to 1.0.

RMP Revolving Credit Facility

On December 22, 2014, Rice Midstream OpCo, LLC, a wholly-owned subsidiary of the Partnership ("Rice Midstream OpCo"), entered into a revolving credit facility ("RMP Revolving Credit Facility") with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders with a maximum credit amount of \$450.0 million and a sublimit for letters of credit of \$50.0 million. As of December 31, 2014, Rice Midstream OpCo had no borrowings outstanding and no letters of credit under this facility. The credit facility is available to fund working capital requirements and capital expenditures, to purchase assets, to pay distributions and repurchase units and for general partnership purposes. The RMP Revolving Credit Facility matures on December 22, 2019. The Partnership is the guarantor of the obligations under the credit facility.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Rice Midstream OpCo has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the applicable LIBOR Rate plus an applicable margin ranging from 175 to 275 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 75 to 175 basis points, depending on the leverage ratio then in effect. Rice Midstream OpCo also pays a commitment fee based on the undrawn commitment amount ranging from 35 to 50 basis points. The RMP Revolving Credit Facility is secured by mortgages and other security interests on substantially all of the properties of, and guarantees from, the Partnership and its restricted subsidiaries.

The RMP Revolving Credit Facility limits the ability of the Partnership and its restricted subsidiaries to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
 - merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The RMP Revolving Credit Facility also requires the Partnership to maintain the following financial ratios:

an interest coverage ratio, which is the ratio of the Partnership's consolidated EBITDA (as defined within the revolving credit facility) to its consolidated current interest expense of at least 2.50 to 1.0 at the end of each fiscal quarter;

a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 4.75 to 1.0, and after electing to issue senior unsecured notes, a consolidated total leverage ratio of not more than 5.25 to 1.0, and, in each case, with certain increases in the permitted total leverage ratio following the completion of a material acquisition; and

if the Partnership elects to issue senior unsecured notes, a consolidated senior secured leverage ratio, which is the ratio of consolidated senior secured debt to consolidated EBITDA, of not more than 3.50 to 1.0.

Second Lien Term Loan Facility (c)

On April 25, 2013, Rice Drilling B entered into a Second Lien Term Loan Facility (the “Second Lien Term Loan Facility”) with Barclays Bank PLC, as administrative agent, and a syndicate of lenders in an aggregate principal amount of \$300.0 million. Rice Drilling B estimated the discount on issuance of this instrument based upon an estimate of market rates at the inception of the instrument and recorded a discount of \$4.5 million. The discount was being amortized over the life of the note using an effective interest rate of 0.284%. Approximately \$7.4 million in fees were capitalized in connection with the Second Lien Term Loan Facility.

On April 25, 2014, the Company used a portion of the net proceeds from the Senior Notes Offering to repay and retire the Second Lien Term Loan Facility in the amount of \$301.8 million. The payment was comprised of repayment of the principal balance of \$297.0 million, a pre-payment penalty of \$3.0 million and accrued but unpaid interest of \$1.8 million. The pre-payment penalty is presented as loss on extinguishment of debt in the consolidated statements of operations for the year ended December 31, 2014. The pre-payment also resulted in a debt extinguishment and subsequent write-off of the unamortized deferred finance costs of \$6.9 million presented in the consolidated statements of operations for the year ended December 31, 2014.

Debentures (d)

In June of 2011, Rice Drilling B sold \$60.0 million of its 12% Senior Subordinated Convertible Debentures due 2014 (the “Debentures”) in a private placement to certain accredited investors as defined in Rule 501 of Regulation D. The Debentures accrued interest at 12% per year payable monthly in arrears by the 15th day of the month and had a scheduled maturity date of July 31, 2014 (“Maturity Date”). The Debentures were Rice Drilling B’s unsecured senior obligations and ranked equally with all of Rice Drilling B’s then-current and future senior unsecured indebtedness.

From July 31, 2013 through August 20, 2013 (the “put redemption period”), any holder of Debentures had the right to cause Rice Drilling B to repurchase all or any portion of the Debentures owned by such holder at 100% of the portion of the principal amount of the Debentures as to which the right was being exercised, plus a premium of 20%. During the put redemption period, Rice Drilling B repurchased \$53.1 million of outstanding Debentures and paid a put premium of \$10.6 million in accordance with the terms of the agreements.

At any time after July 31, 2013 until the Maturity Date, Rice Drilling B had the right to redeem all, but not less than all, of the Debentures on 30 days prior written notice at a redemption price equal to 100% of the principal amount of the Debentures plus a premium of 50%. In connection with our IPO, the Debentures and warrants of Rice Drilling B were amended to become convertible or exercisable for shares of common stock of the Company. On February 28, 2014, Rice Drilling B issued a redemption notice on the remaining Debentures, which set a redemption date of March 28, 2014. Prior to the redemption date, \$6.6 million of the Debentures were converted into 570,945 shares of the Company’s common stock. The premium of \$0.1 million was recorded to expense in the year ended December 31, 2014. As of December 31, 2014, the remaining principal balance was \$0.2 million, which is included in other accrued liabilities on the consolidated balance sheet.

In connection with the convertible debenture offering, Rice Drilling B granted warrants that were issued on August 15, 2011 to certain of the broker-dealers involved in the private placement. These warrants are considered to be separate instruments issued solely in lieu of cash compensation for services provided by the broker-dealers. Two separate classes of warrants were issued with the sole difference being the exercise price. At December 31, 2014, 90 warrants remain exercisable at a weighted average price of \$11.57 per share of the Company’s common stock. The 90 warrants are exercisable in exchange for up to 77,363 shares. For the year ended December 31, 2014, warrants were exercised in exchange for 686,006 shares of the Company’s common stock.

Expected Aggregate Maturities

Expected aggregate maturities of notes payable as of December 31, 2014 are as follows (in thousands):

Year Ending December 31, 2015	\$680
Year Ending December 31, 2016	—
Year Ending December 31, 2017	—
Year Ending December 31, 2018	—
Year Ending December 31, 2019 and Beyond	900,000
Total	\$900,680

Interest paid in cash was \$38.4 million, \$27.7 million and \$10.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. See Note 1 for information on capitalized interest.

4. Derivative Instruments

The Company uses derivative commodity instruments that are placed with major financial institutions whose creditworthiness is regularly monitored. Our derivative counterparties share in the Amended Credit Agreement collateral. The Company's derivative commodity instruments have not been designated as hedges for accounting purposes; therefore, all gains and losses are recognized in income currently. As of December 31, 2014, the Company has entered into derivative instruments with various financial institutions, fixing the price it receives for a portion of its natural gas through December 1, 2017, as summarized in the following table:

Swap Contract Expiration	MMBtu/day	Weighted Average Price
Year ending December 31, 2015:		
NYMEX	166,000	\$4.09
TCO	29,000	\$3.30
Dominion South	71,000	\$2.53
Year ending December 31, 2016:		
NYMEX	214,000	\$4.14
Dominion South	31,000	\$2.62
Year ending December 31, 2017:		
NYMEX	60,000	\$4.24
Collar Contract Expiration	MMBtu/day	Floor/Ceiling
Year ending December 31, 2015:		
NYMEX	139,000	\$3.96/\$4.65
Basis Contract Expiration	MMBtu/day	Swap (\$/MMBtu)
Year ending December 31, 2015:		
TCO	37,000	\$(0.42)
Year ending December 31, 2016:		
TCO	17,000	\$(0.42)

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets for the periods presented, all at fair value:

As of December 31, 2014			
(in thousands)	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting arrangements	Derivative Instruments, net
Derivative assets	\$201,775	\$(5,553) \$196,222
Derivative liabilities	\$—	\$—	\$—
As of December 31, 2013			
(in thousands)	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting arrangements	Derivative Instruments, net
Derivative assets	\$13,000	\$(4,700) \$8,300
Derivative liabilities	\$256	\$(4,600) \$(4,344)

The following table presents the realized and unrealized gains or losses presented as gain or loss on derivatives in the consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012:

(in thousands)	December 31,		
	2014	2013	2012
Realized gain (loss)	\$(18,784) \$676	\$879
Unrealized gain (loss)	\$205,261	\$6,215	\$(2,260)

5. Fair Value of Financial Instruments

The Company determines fair value on a recurring basis for its liability related to restricted units and recorded amounts for derivative instruments as these instruments are required to be recorded at fair value for each reporting amount. Certain amounts in the Company's financial statements were measured at fair value on a nonrecurring basis including discounts associated with long-term debt. Fair value is based on quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use as inputs market-based parameters, including but not limited to forward curves, discount rates, broker quotes, volatilities, and nonperformance risk.

The Company has categorized its fair value measurements into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The Company's fair value measurements relating to restricted units are included in Level 3. The Company's fair value measurements relating to derivative instruments are included in Level 2. Since the adoption of fair value accounting, the Company has not made any changes to its classification of financial instruments in each category.

Items included in Level 3 are valued using internal models that use significant unobservable inputs. Items included in Level 2 are valued using management's best estimate of fair value corroborated by third-party quotes.

The following assets and liabilities were measured at fair value on a recurring basis during the period (refer to Note 4 for details relating to derivative instruments):

		As of December 31, 2014			
(in thousands)		Fair Value Measurements at Reporting Date Using			
(in thousands)	Carrying Value	Total Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:					
Derivative instruments, at fair value	\$ 196,222	\$ 196,222	\$ —	\$ 196,222	\$ —
Total assets	\$ 196,222	\$ 196,222	\$ —	\$ 196,222	\$ —
Liabilities:					
Derivative instruments, at fair value	\$ —	\$ —	\$ —	\$ —	\$ —
Total liabilities	\$ —	\$ —	\$ —	\$ —	\$ —
		As of December 31, 2013			
(in thousands)	Carrying Value	Total Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:					
Derivative instruments, at fair value	\$ 4,921	\$ 4,921	\$ —	\$ 4,921	\$ —
Total assets	\$ 4,921	\$ 4,921	\$ —	\$ 4,921	\$ —
Liabilities:					
Restricted units, at fair value	\$ 36,306	\$ 36,306	\$ —	\$ —	\$ 36,306
Derivative instruments, at fair value	965	965	—	965	—
Total liabilities	\$ 37,271	\$ 37,271	\$ —	\$ 965	\$ 36,306
		Fair Value Measurements Using Significant Unobservable Inputs (Level 3)			
(in thousands)			2014	2013	
Balance as of January 1			\$ 36,306	\$ 5,667	
Total gain or losses:					
Included in earnings			—	32,906	
Repurchase of restricted units			—	(2,267)
Converted to shares of common stock			(36,306)	—
Balance as of December 31			\$ —	\$ 36,306	

In conjunction with the IPO, certain restricted units of Rice Drilling B were exchanged for shares of the Company's common stock. Gains and losses related to restricted units included in earnings for the period are reported in operating expenses in the statements of consolidated operations.

The carrying value of cash equivalents approximates fair value due to the short maturity of the instruments.

The estimated fair value and carrying amount of long-term debt as reported on the consolidated balance sheets as of December 31, 2014 and 2013 is shown in the table below (refer to Note 3 for details relating to the borrowing arrangements). The fair value was estimated using Level 2 inputs based on rates reflective of the remaining maturity as well as the Company's financial position.

	As of December 31, 2014		As of December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-Term Debt (in thousands)				
Senior Notes Offering	\$900,000	\$839,250	\$—	\$—
Second Lien Term Loan Facility	—	—	293,821	315,284
Senior Secured Revolving Credit Facility	—	—	115,000	115,000
Debentures	—	—	6,890	12,671
NPI Note	—	—	8,028	8,028
Other	680	680	3,203	3,203
Total	\$900,680	\$839,930	\$426,942	\$454,186

6. Rice Midstream Partners LP

On December 22, 2014, the Partnership, a subsidiary of the Company, completed the RMP IPO of 28,750,000 common units representing limited partner interests in the Partnership, which represented 50.0% of the Partnership's outstanding equity. The Company retained a 50.0% limited partner interest in the Partnership, consisting of 3,623 common units and 28,753,623 subordinated units. In connection with the RMP IPO, the Company contributed to the Partnership 100% of Rice Poseidon Midstream, LLC ("Rice Poseidon"). A wholly-owned subsidiary of the Company serves as the general partner of the Partnership. The Company continues to consolidate the results of the Partnership and records an income tax provision only as to its ownership percentage. The Company records the noncontrolling interest of the public limited partners in its consolidated financial statements.

The Partnership received cash proceeds, net of issuance costs, of approximately \$441.7 million upon the closing of the RMP IPO, which increased the noncontrolling interest component of total equity. Approximately \$414.4 million of the proceeds were distributed to the Company, \$25.0 million was retained by the Partnership to fund certain expansion capital expenditures, approximately \$2.0 million was used to pay expenses from the RMP IPO and \$2.7 million was used by the Partnership to pay credit facility origination fees associated with the RMP Revolving Credit Facility.

On January 30, 2015, the Board of Directors of the Partnership's general partner declared a cash distribution to the Partnership's unitholders for the fourth quarter of 2014 of \$0.0204 per common and subordinated unit. The cash distribution was paid on February 20, 2015 to unitholders of record at the close of business on February 11, 2015. Net income attributable to noncontrolling interests was \$0.6 million for the year ended December 31, 2014. The Partnership made no distributions to limited partners during the year ended December 31, 2014.

7. Acquisitions

Marcellus JV Buy-In

Prior to the completion of the Marcellus JV Buy-In, the Company accounted for its 50% equity interest in the Marcellus joint venture under the equity method of accounting. Immediately prior to the completion of the Marcellus JV Buy-In, the fair value of the existing equity in the Marcellus joint venture was approximately \$250.6 million. The acquisition date fair value of the existing equity investment was based on an income approach. The income approach, considered to be a Level 3 fair value method, calculated the present value of the future cash flows related to the natural gas properties as of the date of the transaction, utilizing a discount rate based upon market participant assumptions, natural gas strip prices as of the date of the transaction, and a decline curve consistent with our geographic peers. As a result of the Marcellus JV Buy-In, the Company was required to remeasure its equity investment at fair value, which resulted in a non-recurring gain of approximately \$203.6 million during the year ended December 31, 2014. Based on valuations performed as of the acquisition date, the natural gas properties had a fair value of approximately \$343.0 million. The acquisition consolidated the resources of the Company and the Marcellus joint venture, which enabled management to optimize and prioritize the development of their combined natural gas properties. The management team of the Company historically served as the management team of the Marcellus joint venture, providing it with familiarity with its assets and operations. As a result of these factors, the excess purchase price over net assets and liabilities assumed of \$334.0 million was allocated to goodwill.

The purchase price allocation and resulting impact on the corresponding consolidated balance sheet relating to the Marcellus JV Buy-In is as follows:

(in thousands)

Financial assets	\$ 34,242	
Proved natural gas properties, net	288,000	
Unproved natural gas properties	55,000	
Goodwill	334,050	
Financial liabilities	(49,313)
Long-term debt	(75,400)
Deferred tax liability	(13,947)
Total identifiable net assets	\$ 572,632	

Cash paid for acquisitions	\$ 100,000
Fair value of equity issued	222,000
Fair value of pre-existing equity investment	250,632
Total consideration	\$ 572,632

Subsequent to the completion of the Marcellus JV Buy-In and excluding the related gain of \$203.6 million recorded at January 29, 2014, the 100%-owned Marcellus joint venture contributed the following to the Company's consolidated operating results for the year ended December 31, 2014:

(in thousands)	Year Ended December 31, 2014
Revenue	\$ 141,007
Net income	\$ 68,058

Pro Forma Information (Unaudited)

The following unaudited pro forma combined financial information presents the Company's results as though the Marcellus JV Buy-In had been completed at January 1, 2014 and January 1, 2013, respectively.

	Year Ended December 31,	
(in thousands, except per share data)	2014	2013
Pro forma net revenues	\$ 402,878	\$ 179,281
Pro forma net income (loss) attributable to Rice Energy	\$ 19,986	\$ (16,462
Pro forma earnings (loss) per share (basic)	\$ 0.16	\$ (0.14
Pro forma earnings (loss) per share (diluted)	\$ 0.16	\$ (0.14

Momentum Acquisition

On February 12, 2014, the Company, through its then indirect wholly-owned subsidiary Rice Poseidon entered into a purchase and sale agreement with M3 Appalachia Gathering LLC, a Delaware limited liability company ("M3"), to acquire certain gas gathering assets in eastern Washington and Greene Counties, Pennsylvania. On April 17, 2014, the Company completed the Momentum Acquisition for aggregate consideration of approximately \$111.4 million (the "Purchase Price"). The Company funded the Purchase Price with cash on hand. The Purchase Price was allocated to intangible assets related to customer contracts of \$48.9 million and the remaining balance was recorded to proved and unproved natural gas properties.

The properties acquired in the Momentum Acquisition consist of a 28-mile, 6-16 inch gathering system in eastern Washington County, Pennsylvania, and permits and rights of way in Washington and Greene Counties, Pennsylvania, necessary to construct an 18-mile, 30 inch gathering system connecting the northern system to the Texas Eastern pipeline, which we placed into service in November 2014. The northern system is supported by long-term contracts with acreage dedications covering

approximately 21,000 acres from third parties. Once fully constructed, the acquired systems are expected to have an aggregate capacity of over 1 billion cubic feet of natural gas per day.

Greene County Acquisition

On July 7, 2014, the Company entered into a definitive purchase and sale agreement to acquire approximately 22,000 net acres and 12 developed Marcellus wells in southwestern Greene County, Pennsylvania from Chesapeake Appalachia, L.L.C. and its partners for approximately \$329.5 million (the "Greene County Acquisition"). The purchase price was allocated to proved and unproved natural gas properties in the amounts of \$151.3 million and \$178.2 million, respectively. The transaction closed on August 1, 2014, with an effective date of February 1, 2014. The Company funded the Greene County Acquisition with cash on hand. The purchase price allocation for this acquisition is preliminary as of December 31, 2014 and subject to remaining purchase price revisions.

8. Financial Information by Business Segment

Management has evaluated how the Company is organized and has identified the exploration and production segment and the midstream segment as separate reportable segments. Operating segments are evaluated on their contribution to the Company's consolidated results based on operating income. Other income and expenses, interest and income taxes are managed on a consolidated basis. The segment accounting policies are the same as those described in Note 1 of these consolidated financial statements. The operating results and assets of the Company's reportable segments were as follows as of and for the year ended December 31, 2014:

(in thousands)	Expoloration and Production	Midstream	Elimination of Intersegment Transactions	Consolidated Total
Operating revenues:				
Natural gas, oil and NGL sales	\$359,201	\$—	\$—	\$359,201
Firm transportation sales, net	26,237	—	—	26,237
Other revenue	—	7,300	(1,796)	5,504
Total operating revenues	\$385,438	\$7,300	\$(1,796)	\$390,942
Operating expenses:				
Depreciation, depletion and amortization	\$151,900	\$4,370	\$—	\$156,270
Exploration	4,018	207	—	4,225
Lease operating	24,971	—	—	24,971
Gathering, compression and transportation	37,414	4,607	(1,796)	40,225
Production taxes and fees	4,647	—	—	4,647
Incentive unit expense	86,020	19,941	—	105,961
Stock compensation expense	4,532	1,021	—	5,553
Acquisition costs	820	1,519	—	2,339
Amortization of intangible assets	—	1,156	—	1,156
General and administrative expenses	41,697	14,320	—	56,017
Total operating expenses	\$356,019	\$47,141	\$(1,796)	\$401,364
Operating income (loss)	\$29,419	\$(39,841)	\$—	\$(10,422)
Segment assets				
Goodwill	\$2,935,814	\$592,135	\$—	\$3,527,949
Capital expenditures for segment assets	\$294,908	\$39,142	\$—	\$334,050
	\$765,491	\$367,950	\$—	\$1,133,441

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The operating results and assets of the Company's reportable segments were as follows as of and for the year ended December 31, 2013:

(in thousands)	Exploration and Production	Midstream	Consolidated Total
Operating revenues:			
Natural gas, oil and NGL sales	\$87,847	\$—	\$87,847
Other revenue	259	581	840
Total operating revenues	\$88,106	\$581	\$88,687
Operating expenses:			
Depreciation, depletion and amortization	\$31,467	\$1,348	\$32,815
Exploration	9,951	—	9,951
Lease operating	8,309	—	8,309
Gathering, compression and transportation	8,362	1,412	9,774
Production taxes and fees	1,629	—	1,629
Restricted unit expense	32,906	—	32,906
Loss from sale of interest in gas properties	4,230	—	4,230
General and administrative expenses	13,778	3,175	16,953
Total operating expenses	\$110,632	\$5,935	\$116,567
Operating loss	\$(22,526)) \$(5,354)) \$(27,880)
Segment assets	\$804,992	\$74,818	\$879,810
Capital expenditures for segment assets	\$442,654	\$45,980	\$488,634

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The operating results and assets of the Company's reportable segments were as follows as of and for the year ended December 31, 2012:

(in thousands)	Exploration and Production	Midstream	Consolidated Total
Operating revenues:			
Natural gas, oil and NGL sales	\$26,743	\$—	\$26,743
Other revenue	457	—	457
Total operating revenues	\$27,200	\$—	\$27,200
Operating expenses:			
Depreciation, depletion and amortization	\$13,365	\$784	\$14,149
Exploration	3,275	—	3,275
Lease operating	3,688	—	3,688
Gathering, compression and transportation	2,536	1,218	3,754
Production taxes and fees	1,382	—	1,382
Write down of abandoned leases	2,253	—	2,253
General and administrative expenses	6,821	778	7,599
Total operating expenses	\$33,320	\$2,780	\$36,100
Operating loss	\$(6,120) \$(2,780) \$(8,900
Segment assets	\$314,687	\$30,283	\$344,970
Capital expenditures for segment assets	\$118,986	\$15,558	\$134,544

9. Commitments and Contingencies

On October 14, 2013, the Company entered into a Development Agreement and Area of Mutual Interest ("AMI") Agreement with Gulfport Energy Corporation ("Gulfport") covering approximately 50,000 aggregate net acres in the Utica Shale in Belmont County, Ohio. The Company refers to these agreements as "Utica Development Agreements." Pursuant to the Utica Development Agreements, the Company had approximately 68.7% participating interest in acreage currently owned or to be acquired by the Company or Gulfport located within Goshen and Smith Townships (the "Northern Contract Area") and an approximately 48.2% participating interest in acreage currently owned or to be acquired by the Company or Gulfport located within Wayne and Washington Townships (the "Southern Contract Area"), each within Belmont County, Ohio. The remaining participating interests are held by Gulfport. The participating interests of the Company and Gulfport in each of the Northern and Southern Contract Areas approximated the Company's then-current relative acreage positions in each area.

The Utica Development Agreements have terms of ten years and are terminable upon 90 days' notice by either party; provided that, with respect to interests included within a drilling unit, such interests shall remain subject to the applicable joint operating agreement and the Company and Gulfport shall remain operators of drilling units located in the Northern and Southern Contract Areas, respectively, following such termination.

The Company has commitments for gathering and firm transportation under existing contracts with third parties. Future payments under these contracts as of December 31, 2014 totaled \$4,891.9 million (2015 - \$94.3 million, 2016 - \$117.2 million, 2017 - \$136.8 million, 2018 - \$197.7 million, 2019 - \$222.6 million and thereafter - \$4,123.3 million). As of December 31, 2014, the Company had seven drilling rigs (four horizontal and three top-hole) under contract, of which five expire in 2015 and two expire in 2017. Future payments under these contracts as of December 31, 2014 totaled \$77.6 million (2015 - \$49.5 million, 2016 - \$21.2 million and 2017 - \$6.9 million). Any other rig performing work for us is performed on a well-by-well basis and therefore can be released without penalty at the conclusion of drilling on the current well. These types of drilling obligations have not been included in the amounts above. The values above represent the gross amounts that we are committed to pay without regard to our proportionate share based on our working interest.

The Company is involved in various litigation matters arising in the normal course of business. Management is not aware of any actions that are expected to have a material adverse effect on its financial position or results of operations.

10. Lease Obligations

The Company leases drilling rights under agreements which expire at various times. The following represents the future minimum lease payments under the agreements as of December 31, 2014:

(in thousands)

2015	\$30,702
2016	3,769
2017	482
2018	28
2019 and thereafter	—
Total future minimum lease payments	\$34,981

These lease payments are included as leasehold payable in the accompanying consolidated balance sheets.

Additionally, the Company has leased drilling rights under agreements which specify additional payments due in the event that the Company does not meet predetermined criteria within a specified period of time. The Company could be required to pay up to approximately \$0.9 million, of which, \$0.8 million would be due in 2015 under these agreements.

11. Asset Retirement Obligations

The Company is subject to certain legal requirements which result in recognition of a liability related to the obligation to incur future plugging and abandonment costs. The Company records a liability for such asset retirement obligations and capitalizes a corresponding amount for asset retirement costs. The liability is estimated using the present value of expected future cash flows, adjusted for inflation and discounted at the Company's credit adjusted risk-free rate.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations for the years ended December 31, 2014 and 2013 is as follows:

(in thousands)

Balance at December 31, 2012	\$1,380	
Liabilities incurred	583	
Accretion expense	151	
Balance at December 31, 2013	\$2,114	
Liabilities incurred	7,171	
Liabilities settled	(256)
Accretion expense	513	
Balance at December 31, 2014	\$9,542	

12. Stockholders' Equity

On January 29, 2014, pursuant to the Master Reorganization Agreement (the "Master Reorganization Agreement") among the Company, Rice Drilling B, Rice Appalachia, Rice Holdings, Rice Partners, NGP Holdings, NGP RE Holdings, L.L.C., ("NGP RE Holdings") NGP RE Holdings II, L.L.C. ("NGP RE II" and, together with NGP RE Holdings, "Natural Gas Partners"), Mr. Daniel J. Rice III, Rice Merger LLC ("Merger Sub") and each of the persons holding incentive units representing interests in Rice Appalachia (collectively, the "Incentive Unitholders") dated as of January 23, 2014, (i) (a) Rice Partners contributed a portion of its interests in Rice Appalachia to Rice Holdings, (b) Natural Gas Partners contributed its interests in Rice Appalachia to NGP Holdings and (c) the Incentive Unitholders contributed a portion of their incentive units to Rice Holdings and NGP Holdings, in each case in return for substantially similar incentive units in such entities; (ii) NGP Holdings, Rice Holdings and Mr. Daniel J. Rice III contributed their respective interests in Rice Appalachia to the Company in exchange for 43,452,550, 20,300,923 and 2,356,844 shares of common stock, respectively; (iii) Rice Partners contributed its remaining interest in Rice Appalachia to the Company in exchange for 20,000,000 shares of common stock; (iv) the Incentive Unitholders contributed their remaining interests in Rice Appalachia to the Company in exchange for 160,831 shares of common stock, each of which were

issued by the Company in connection with the closing of our IPO. In connection with our IPO, in the first quarter of 2014, we recognized non-cash compensation expense of \$3.4 million for these 160,831 shares.

In addition, on January 29, 2014, pursuant to the Agreement and Plan of Merger (the “Merger Agreement”) among the Company, Rice Drilling B and Merger Sub dated as of January 23, 2014, the Company issued 1,728,852 shares of common stock to the members of Rice Drilling B (other than Rice Appalachia) in exchange for their units in Rice Drilling B.

In August 2014, the Company completed an offering of 13,729,650 shares of common stock at \$27.30 per share (the “August 2014 Equity Offering”), which included 7,500,000 shares sold by the Company and 6,229,650 shares sold by affiliates of NGP Holdings and Alpha Holdings (the “Selling Stockholders”). After deducting underwriting discounts and commissions of \$7.7 million and transaction costs, the Company received net proceeds of \$196.3 million. The Company received no proceeds from the sale of shares by the Selling Stockholders. The net proceeds from this offering were used to fund a portion of the Company’s 2014 capital budget.

On December 22, 2014, the Partnership, a subsidiary of the Company, completed the RMP IPO of 28,750,000 common units representing limited partner interests in the Partnership, which represented 50.0% of the Partnership's outstanding equity. The Company retained a 50.0% equity interest in the Partnership, including 3,623 common units and 28,753,623 subordinated units. See Note 6 for further discussion of the RMP IPO.

The Company’s Board of Directors did not declare or pay a dividend to holders of Rice Energy common stock for the year ended December 31, 2014 or 2013.

13. Incentive Units

In connection with our IPO and the related corporate reorganization, the Rice Appalachia incentive unit holders contributed their Rice Appalachia incentive units to Rice Holdings and NGP Holdings in return for substantially similar incentive units in such entities (except for those incentive units related to the incentive burden attributable to Mr. Daniel J. Rice III, which we acquired from the holders of such incentive units in exchange for the issuance of 160,831 shares of our common stock). In the first quarter of 2014, certain incentive units granted by NGP Holdings to certain employees triggered the pre-determined payout criteria, resulting in a cash payment by NGP Holdings of \$4.4 million. No payments were made in respect of incentive units prior to the completion of our IPO. These two transactions resulted in non-cash compensation expense of \$7.8 million being recorded in the first quarter of 2014 by the Company. As a result of our IPO, the payment likelihood related to the incentive units was deemed probable, requiring the Company to recognize expense.

For the year ended December 31, 2014, we recognized approximately \$106.0 million of compensation expense, relative to these interests, of which \$19.8 million has been paid by Mr. Daniel J. Rice III and NGP Holdings for the year ended December 31, 2014. We expect to recognize approximately \$72.8 million of additional compensation expense over the remaining expected service periods related to the Rice Holdings interests. The NGP Holdings interests are considered a liability-based award and will be adjusted to fair market value on a quarterly basis until all payments have been made. As of December 31, 2014, the unrecognized compensation expense related to the NGP Holdings units is approximately \$52.0 million. The compensation expense related to these interests is treated as additional paid in capital from Rice Holdings and NGP Holdings in our financial statements and is not deductible for federal or state income tax purposes. The compensation expense recognized is a non-cash charge, with the settlement obligation resting on NGP Holdings and Rice Holdings, and as such are not dilutive to Rice Energy Inc.

In August 2014, the triggering event for the Rice Holdings incentive units was achieved. As a result, in August of 2015, 2016 and 2017, Rice Holdings will distribute one third, one half and all, respectively, of its then-remaining assets (consisting solely of shares of our common stock) to its members pursuant to the terms of its limited liability company agreement. As a result, over time, the shares of our common stock held by Rice Holdings will be transferred in their entirety to Rice Energy Irrevocable Trust and the incentive unitholders.

As a result of the August 2014 Equity Offering, NGP Holdings paid approximately \$12.0 million in the aggregate to holders of certain NGP Holdings incentive units.

Three tranches of the incentive units have a time vesting feature. A rollforward of those units from our IPO to December 31, 2014 is included below.

Vested Units Balance, January 29, 2014	133,333	
Vested During Period	1,667,578	
Forfeited During Period	(37,140))
Granted During Period	37,140	
Cancelled During Period	—	
Vested Units Balance, December 31, 2014	1,800,911	

Four tranches of the incentive units do not have a time vesting feature, and their payouts are triggered upon a future payment condition. As such, none of these awards have legally vested as of December 31, 2014. The fair value of the incentive units was estimated using a Monte Carlo simulation valuation model with the following assumptions:

Rice Holdings		
Valuation Date	1/29/2014	
Dividend Yield	0.00	%
Expected Volatility	47.00	%
Risk-Free Rate	1.11	%
Expected Life (Years)	4.0	
Rice Holdings		
Valuation Date	4/14/2014	
Dividend Yield	0.00	%
Expected Volatility	45.19	%
Risk-Free Rate	1.13	%
Expected Life (Years)	3.8	
Rice Holdings		
Valuation Date	4/16/2014	
Dividend Yield	0.00	%
Expected Volatility	44.32	%
Risk-Free Rate	1.18	%
Expected Life (Years)	3.8	
NGP Holdings		
Valuation Date	12/31/2014	
Dividend Yield	0.00	%
Expected Volatility	63.75	%
Risk-Free Rate	0.56	%
Expected Life (Years)	1.75	

14. Stock-Based Compensation

During the year ended December 31, 2014, the Company granted stock-based compensation awards to certain non-employee directors and employees under our long-term incentive plan (the "LTIP"). Pursuant to the LTIP, the Company expects the aggregate maximum number of shares of our common stock issued under the LTIP will not exceed 17,500,000. The awards consisted of restricted stock units, which vest upon the passage of time, and performance units, which vest based upon attainment of specified company performance criteria.

Restricted Stock Unit Awards

Restricted stock awards are valued based upon the price of the Company's common stock on the grant date and vest over periods from one to three years, with compensation expense being recognized on a straight-line basis over the requisite service period. Compensation expense related to the restricted stock unit awards was \$2.6 million for the year ended December 31, 2014. The following table summarizes the restricted stock unit award activity during the year ended December 31, 2014.

	Number of units	Weighted average grant date fair value
--	--------------------	--

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Total unvested, January 1, 2014	—	\$—
Granted	329,008	28.79
Vested	(1,647) 30.33
Forfeited	(3,538) 32.59
Total unvested - December 31, 2014	323,823	\$28.74

The following table details the scheduled vesting of the outstanding unvested restricted stock unit awards at December 31, 2014.

Vesting Date	Number of units
2015	138,929
2016	92,447
2017	92,447
	323,823

No shares were exercised in the year ended December 31, 2014. Total unrecognized compensation expense expected to be recognized in the future related to the restricted stock unit awards as of December 31, 2014 is \$6.8 million.

Performance Stock Unit Awards

We use a Monte Carlo simulation valuation model to determine the fair value of the performance stock unit awards on the grant date. The compensation expense related to these awards is being recognized on a straight-line basis and the awards will cliff vest over the requisite service period of approximately three years. Compensation expense related to the performance unit stock awards was \$2.8 million for the year ended December 31, 2014. The following table presents information regarding the assumptions used in determining the fair value of the performance stock unit awards at December 31, 2014.

Dividend Yield	0.00	%
Expected Volatility	43.73	%
Risk-Free Rate	0.70	%
Expected Life (Years)	2.65	
Weighted average fair value of performance stock unit awards	\$38.77	

Total unrecognized compensation expense expected to be recognized in the future related to the performance stock unit awards as of December 31, 2014 is \$8.7 million.

RMP Phantom Unit Awards

In connection with the closing of the RMP IPO, the Partnership's general partner granted phantom unit awards under the Rice Midstream Partners LP 2014 Long Term Incentive Plan (the "RMP LTIP") to certain non-employee directors of the

Partnership and executive officers and employees of Rice Energy. Pursuant to the RMP LTIP, the maximum aggregate number of common units that may be issued pursuant to any and all awards under the RMP LTIP shall not exceed 5,000,000 common units subject to adjustment due to recapitalization or reorganization, or related to forfeitures or the expiration of Awards, as provided under the RMP LTIP. In connection with the RMP IPO, 9,333 common units were granted that are accounted for as liability-based awards, expected to be settled in cash, and 435,549 common units were granted that are accounted for as equity-based awards expected to be settled in common units. The liability-based awards will be adjusted to fair market value on a quarterly basis and will cliff vest at the end of the requisite service period of one and a half years. The equity-based awards are valued based upon the price of the Partnership's common units on the grant date and will cliff vest over the requisite service period from one and a half to two years. The Partnership recorded \$0.1 million of stock compensation expense related to these awards in the year ended December 31, 2014. Total unrecognized compensation expense expected to be recognized over the remaining vesting period as of December 31, 2014 is \$6.9 million for these awards.

The following table summarizes the activity for the equity-based awards during the year ended December 31, 2014.

	Number of units	Weighted average grant date fair value
Total unvested, January 1, 2014	—	\$—
Granted	435,549	16.50
Vested	—	
Forfeited	—	
Total unvested - December 31, 2014	435,549	\$ 16.50

The following table details the scheduled vesting of the unvested equity-based awards at December 31, 2014.

Vesting Date	Number of shares
2015	—
2016	435,549
	435,549

15. Earnings Per Share

Basic EPS is computed by dividing net income (loss) by the weighted-average number of shares of common stock outstanding during the period. Diluted earnings per share takes into account the dilutive effect of potential common stock that could be issued by the Company in conjunction with stock awards that have been granted to directors and employees as well as outstanding warrants issued to certain broker-dealers involved with the placement of our former convertible debentures. The following is a calculation of the basic and diluted weighted-average number of shares of common stock outstanding and EPS for the years ended December 31, 2014, 2013 and 2012. As indicated in Note 1, our corporate reorganization was considered a transaction amongst entities under common control. Therefore, the weighted average shares used in our EPS calculation assume that the Rice Energy Inc. corporate structure was in place for all periods presented.

	Year Ended December 31,		
	2014	2013	2012
Income (loss) (numerator):			
Net income (loss) attributable to Rice Energy (in thousands)	\$218,454	\$(35,776)	\$(19,344)
Weighted-average shares (denominator):			
Weighted-average number of shares of common stock - basic	128,151,171	80,441,905	58,231,763
Weighted-average number of shares of common stock - diluted	128,225,155	80,441,905	58,231,763
Earnings (loss) per share:			
Basic	\$1.70	\$(0.44)	\$(0.33)
Diluted	\$1.70	\$(0.44)	\$(0.33)

Due to the net loss for the periods presented herein, loss per share excludes dilution for 1,671,800 shares for the years ended December 31, 2013 and 2012, respectively.

The impact of the Partnership's dilutive units did not have a material impact on the Company's earnings per share calculation at December 31, 2014.

16. Income Taxes

We are a corporation under the Internal Revenue Code subject to federal income tax at a statutory rate of 35% of pretax earnings. We did not report any income tax benefit or expense for periods prior to the consummation of our IPO in January 2014 because Rice Drilling B, our accounting predecessor, is a limited liability company that was not subject to federal income tax. The reorganization of our business in connection with the closing of our IPO, such that it is now held by a corporation subject to federal income tax, required the recognition of a deferred tax asset or liability for the initial temporary differences at the time of our IPO. The resulting deferred tax liability of approximately \$162.3 million was recorded in equity at the date of the completion of our IPO as it represents a transaction among shareholders. Additionally, the pro forma EPS for the year ended December 31, 2014 disclosed in the accompanying consolidated statements of operations assumes a statutory tax rate. The components of the income tax provision are as follows:

(in thousands)	Year Ended December 31, 2014
Current tax expense:	
Federal	\$3,961
State	—
Total	3,961
Deferred tax expense:	
Federal	68,846
State	18,793
Total	87,639
Total income tax expense	\$91,600

The Company estimates an annual effective income tax rate based on projected results for the year and applies this rate to income before taxes to calculate income tax expense. The effective tax rate for the year ended December 31, 2014 differs from the statutory rate due principally to non-deductible incentive unit expense and, for the year ended December 31, 2014, pre-tax income prior to our IPO.

Income tax expense differs from amounts computed at the federal statutory rate of 35% on pre-tax income as follows:

(in thousands)	Year Ended December 31, 2014
Tax at statutory rate	\$108,722
Permanent tax differences	18
State income taxes	12,216
Partnership earnings (1/1/14 - 1/28/14)	(66,239)
Noncontrolling partners' share of RMP earnings	(203)
Incentive unit expense	37,086
Income tax expense	\$91,600
Effective tax rate	29.49%

The Company recognizes deferred tax liabilities for temporary differences between the financial statement and tax basis of assets and liabilities. The deferred tax liabilities primarily relate to intangible drilling costs, depletion and depreciation. The effect of changes in the tax laws or tax rates is recognized in income in the period such changes are enacted. The following table summarizes the source and tax effects of temporary differences that give rise to the deferred tax assets and deferred tax liabilities at December 31, 2014.

(in thousands)	Year Ended December 31, 2014	
Deferred income taxes:		
Total deferred tax assets	\$—	
Total deferred tax liabilities	(263,906)
Total net deferred tax liabilities	(263,906)
Principal components of deferred tax assets and liabilities:		
Drilling and development costs expensed for tax	(189,475)
Tax depreciation in excess of book depreciation	(24,252)
Investment in partnerships	38,077	
Incentive compensation	2,263	
Hedging loss	(80,663)
AMT tax credit	3,961	
Other	(13,817)
Total	\$(263,906)

Based on management's analysis, the Company did not have any uncertain tax positions as of December 31, 2014.

17. Related Party Transactions

Prior to the completion of the Marcellus JV Buy-In, the Company was reimbursed for costs incurred on behalf of the Company's Marcellus joint venture. General and administrative expenses incurred by the Company and reimbursed by the Company's Marcellus joint venture were \$0.3 million, \$1.6 million and \$1.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Prior to our IPO, the Company reimbursed Rice Partners for expenses incurred on behalf of the Company. General and administrative expenses incurred by Rice Partners and reimbursed by the Company were \$1.8 million, \$9.3 million and \$4.8 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2013 \$6.1 million of general and administrative expenses was due to Rice Partners and is recorded as other accrued liabilities on the consolidated balance sheet. Prior to the closing of our IPO, the Company terminated its agreement to reimburse Rice Partners for expenses incurred on its behalf.

Payments totaling \$3.4 million, \$2.2 million and \$0.8 million were made during the years ended December 31, 2014, 2013 and 2012 respectively to Geological Engineering Services, Inc. ("GES") in respect of consultancy services. GES is a drilling and completion engineering consulting company specializing in unconventional reservoirs like the Marcellus Shale. John P. LaVelle, Rice Energy's Vice President of Drilling, served as president of GES from February 1994 until February 2010. There were no amounts outstanding between the Company and GES as of any period presented.

Upon completion of the RMP IPO, the Company entered into a 15 year, fixed fee gas gathering and compression agreement (the "Gas Gathering and Compression Agreement") with RMP, under which RMP will gather natural gas on RMP's gathering systems located in Washington County and Greene County, Pennsylvania and provide compression services. Pursuant to the Gas Gathering and Compression Agreement, RMP will charge the Company a gathering fee of \$0.30 per Dth and a compression fee of \$0.07 per Dth per stage of compression, each subject to annual adjustment for inflation based on the Consumer Price Index. The Gas Gathering and Compression Agreement covers approximately 65,000 gross acres of the Company's acreage position in the dry gas core of the Marcellus Shale in southwestern Pennsylvania as of December 31, 2014 and any future acreage it acquires within these counties, other than 22,000 gross acres subject to a pre-existing third-party dedication. The revenues and related receivables RMP records pursuant to the Gas Gathering and Compression Agreement are eliminated in consolidation in the accompanying consolidated financial statements.

18. New Accounting Pronouncements

In May 2014, the FASB issued ASU, No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," or ASU No. 2014-09. The FASB created Topic 606 which supersedes the revenue recognition requirements in Topic 605, "Revenue Recognition," and most industry-specific guidance throughout the Industry Topics of the Codification. ASU 2014-09 will enhance comparability of revenue recognition practices across entities, industries and capital markets compared to existing guidance. Additionally, ASU 2014-09 will reduce the number of requirements to which an entity must consider in recognizing revenue as this update will replace multiple locations for guidance. The FASB and International Accounting Standards Board initiated this joint project to clarify the principles for recognizing revenue and to develop a common revenue standard for both U.S. GAAP and International Financial Reporting Standards. ASU 2014-09 is effective for fiscal and interim periods beginning after December 15, 2016 and should be applied retrospectively. Early adoption of this standard is not permitted. The Company is currently evaluating the impact of the provisions of ASU 2014-09.

In February 2015, the FASB issued ASU, 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." ASU 2015-02 affects reporting entities that are required to evaluate whether they should consolidate certain legal entities. ASU 2015-02 is effective for periods beginning after December 15, 2015 with early adoption permitted. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements.

19. Subsequent Events

On February 6, 2015, the Company entered into a Limited Consent and Second Amendment (the "Second Amendment") to its Amended Credit Agreement. The Second Amendment, among other items, increased the borrowing sublimit for letters of credit from \$100.0 million to \$175.0 million and provided a limited consent by the lenders to certain hedging agreements entered into by the Company with respect to calendar months of 2015 exceeding maximum notional volume limitations contained in the Amended Credit Agreement.

20. Guarantor Financial Information

On April 25, 2014, the Company issued \$900.0 million in aggregate principal amount of the Notes. The obligations under the Notes are fully and unconditionally guaranteed by the Guarantors, subject to release provisions described in Note 3. The Company's subsidiaries that constitute its midstream segment, including the Partnership, are unrestricted subsidiaries under the Indenture and consequently are not Guarantors. In accordance with positions established by the Securities and Exchange Commission, the following shows separate financial information with respect to the Company, the Guarantors and the non-guarantor subsidiaries. The principal elimination entries eliminate investment in subsidiaries and certain intercompany balances and transactions.

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Balance Sheet as of December 31,
2014

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Assets					
Current assets:					
Cash and restricted cash	\$ 181,835	\$ 41,934	\$ 32,361	\$—	\$ 256,130
Accounts receivable	1,773	196,974	1,153	—	199,900
Receivable from affiliates	634	55	2,198	(2,799) 88
Derivative assets	47,291	85,743	—	—	133,034
Prepaid expenses and other assets	1,296	1,702	341	—	3,339
Total current assets	232,829	326,408	36,053	(2,799) 592,491
Investments in subsidiaries	2,177,895	86,148	—	(2,264,043) —
Property, plant and equipment, net	10,348	1,986,856	464,127	—	2,461,331
Deferred financing costs, net	20,081	—	5,022	—	25,103
Goodwill	—	294,908	39,142	—	334,050
Intangible assets, net	—	—	47,791	—	47,791
Other non-current assets	8,290	58,893	—	—	67,183
Total assets	\$ 2,449,443	\$ 2,753,213	\$ 592,135	\$(2,266,842) \$ 3,527,949
Liabilities and stockholders' equity					
Current liabilities:					
Current portion of long-term debt	\$—	\$ 680	\$—	\$—	\$ 680
Accounts payable	19,231	101,132	31,966	—	152,329
Royalties payables	—	37,172	—	—	37,172
Leasehold payables	—	30,702	—	—	30,702
Deferred tax liabilities	54,688	39,197	—	(39,197) 54,688
Accrued capital expenditures	1,515	89,858	16,917	—	108,290
Other accrued liabilities	26,027	27,502	2,086	(2,801) 52,814
Total current liabilities	101,461	326,243	50,969	(41,998) 436,675
Long-term liabilities:					
Long-term debt	900,000	—	—	—	900,000
Deferred tax liabilities	12,497	237,155	10,660	(51,094) 209,218
Leasehold payable	—	4,279	—	—	4,279
Other long-term liabilities	3,068	7,641	1,900	—	12,609
Total liabilities	1,017,026	575,318	63,529	(93,092) 1,562,781
Stockholders' equity before noncontrolling interest	1,432,417	2,177,895	86,148	(2,173,750) 1,522,710
Noncontrolling interest	—	—	442,458	—	442,458
Total liabilities and stockholders' equity	\$ 2,449,443	\$ 2,753,213	\$ 592,135	\$(2,266,842) \$ 3,527,949

Balance Sheet as of December 31,
2013

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Assets					
Current assets:					
Cash	\$—	\$31,408	\$ 204	\$—	\$31,612
Restricted cash	—	8,268	—	—	8,268
Accounts receivable	—	31,679	86	—	31,765
Receivable from affiliate	—	2,547	—	(303) 2,244
Prepaid expenses and other	—	863	—	—	863
Total current assets	—	74,765	290	(303) 74,752
Investments in joint ventures and subsidiaries	—	108,804	—	(58,990) 49,814
Gas collateral account	—	3,700	—	—	3,700
Property, plant and equipment, net	—	668,511	65,820	—	734,331
Deferred financing costs, net	—	12,292	—	—	12,292
Other non-current assets	—	4,921	—	—	4,921
Total assets	\$—	\$872,993	\$ 66,110	\$(59,293) \$879,810
Liabilities and stockholders' equity					
Current liabilities:					
Current portion of long-term debt	\$—	\$20,120	\$—	\$—	\$20,120
Accounts payable	—	46,096	5,123	—	51,219
Royalties payable	—	9,393	—	—	9,393
Leasehold payable	—	18,606	—	—	18,606
Accrued capital expenditures	—	15,263	1,490	—	16,753
Other accrued liabilities	—	16,643	507	(303) 16,847
Total current liabilities	—	126,121	7,120	(303) 132,938
Long-term liabilities:					
Long-term debt	—	406,822	—	—	406,822
Leasehold payable	—	1,675	—	—	1,675
Restricted units	—	36,306	—	—	36,306
Other long-term liabilities	—	3,422	—	—	3,422
Total liabilities	—	574,346	7,120	(303) 581,163
Stockholders' equity	—	298,647	58,990	(58,990) 298,647
Total liabilities and stockholders' equity	\$—	\$872,993	\$ 66,110	\$(59,293) \$879,810

Statement of Operations for the Year Ended
December 31, 2014

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Operating revenues:					
Natural gas, oil and natural gas liquids (NGL) sales	\$—	\$359,201	\$—	\$—	\$359,201
Firm transportation sales, net	—	26,237	—	—	26,237
Other revenue	—	—	7,300	(1,796)	5,504
Total operating revenues	—	385,438	7,300	(1,796)	390,942
Operating expenses:					
Lease operating	—	24,971	—	—	24,971
Gathering, compression and transportation	—	37,180	4,607	(1,562)	40,225
Production taxes and impact fees	—	4,647	—	—	4,647
Exploration	—	4,018	207	—	4,225
Incentive unit expense	—	86,020	19,941	—	105,961
Stock compensation expense	—	4,532	1,021	—	5,553
General and administrative	—	40,736	15,281	—	56,017
Depreciation, depletion and amortization	—	153,282	2,988	—	156,270
Acquisition expense	—	820	1,519	—	2,339
Amortization of intangible assets	—	—	1,156	—	1,156
Total operating expenses	—	356,206	46,720	(1,562)	401,364
Operating income (loss)	—	29,232	(39,420)	(234)	(10,422)
Interest expense	(27,177)	(10,130)	(12,884)	—	(50,191)
Gain on purchase of Marcellus joint venture	—	203,579	—	—	203,579
Other income (loss)	247	755	(109)	—	893
Gain on derivative instruments	55,580	130,897	—	—	186,477
Amortization of deferred financing costs	(2,006)	(489)	—	—	(2,495)
Loss on extinguishment of debt	—	(7,654)	—	—	(7,654)
Write-off of deferred financing costs	—	(6,896)	—	—	(6,896)
Equity in income (loss) of joint ventures and subsidiaries	193,119	(47,208)	—	(148,567)	(2,656)
Income (loss) before income taxes	219,763	292,086	(52,413)	(148,801)	310,635
Income tax expense	(91,600)	(98,731)	8,440	90,291	(91,600)
Net income (loss)	128,163	193,355	(43,973)	(58,510)	219,035
Less: net income attributable to noncontrolling interests	—	—	(581)	—	(581)
Net income (loss) attributable to Rice Energy	\$128,163	\$193,355	\$ (44,554)	\$(58,510)	\$218,454

Statement of Operations for the Year Ended
December 31, 2013

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated	
Operating revenues:						
Natural gas sales	\$—	\$87,847	\$ —	\$—	\$87,847	
Other revenue	—	763	77	—	840	
Total operating revenues	—	88,610	77	—	88,687	
Operating expenses:						
Lease operating	—	8,309	—	—	8,309	
Gathering, compression and transportation	—	8,919	855	—	9,774	
Production taxes and impact fees	—	1,629	—	—	1,629	
Exploration	—	9,951	—	—	9,951	
Restricted unit expense	—	32,906	—	—	32,906	
General and administrative	—	16,636	317	—	16,953	
Depreciation, depletion and amortization	—	32,421	394	—	32,815	
Loss from sale of interest in gas properties	—	4,230	—	—	4,230	
Total operating expenses	—	115,001	1,566	—	116,567	
Operating (loss)	—	(26,391) (1,489) —	(27,880)
Interest expense	—	(17,915) —	—	(17,915)
Other (loss)	—	(357) (83) —	(440)
Gain on derivative instruments	—	6,891	—	—	6,891	
Amortization of deferred financing costs	—	(5,230) —	—	(5,230)
Loss on extinguishment of debt	—	(10,622) —	—	(10,622)
Equity in income of joint ventures and subsidiaries	—	17,848	—	1,572	19,420	
Net income (loss)	\$—	\$(35,776) \$ (1,572) \$1,572	\$(35,776)

Statement of Operations for the Year Ended
December 31, 2012

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated	
Operating revenues:						
Natural gas sales	\$—	\$26,743	\$—	\$—	\$26,743	
Other revenue	—	457	—	—	457	
Total operating revenues	—	27,200	—	—	27,200	
Operating expenses:						
Lease operating	—	3,688	—	—	3,688	
Gathering, compression and transportation	—	3,754	—	—	3,754	
Production taxes and impact fees	—	1,382	—	—	1,382	
Exploration	—	3,275	—	—	3,275	
General and administrative	—	7,604	(5)	7,599	
Depreciation, depletion and amortization	—	14,149	—	—	14,149	
Write-down of abandoned leases	—	2,253	—	—	2,253	
Total operating expenses	—	36,105	(5)	36,100	
Operating loss	—	(8,905)	5	(8,900)
Interest expense	—	(3,487)	—	(3,487)
Other income (loss)	—	112	—	—	112	
Gain (loss) on derivative instruments	—	(1,381)	—	(1,381)
Amortization of deferred financing costs	—	(7,220)	—	(7,220)
Equity in income (loss) of joint ventures	—	1,537	—	(5)	1,532
Net income (loss)	\$—	\$(19,344)	\$ 5	\$(19,344)

Condensed Statement of Cash Flows for the Year Ended December 31, 2014

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Net cash provided by (used in) operating activities	\$16,139	\$96,147	\$ (27,211)	\$—	\$85,075
Capital expenditures for natural gas properties	—	(682,344)	(276,936)	—	(959,280)
Acquisition of Marcellus joint venture, net of cash acquired	—	(27,766)	(55,000)	—	(82,766)
Acquisition of Momentum assets	—	(400)	(111,447)	—	(111,847)
Acquisition of Greene County assets	—	(329,469)	—	—	(329,469)
Capital expenditures for property and equipment	(8,588)	(2,197)	(209)	—	(10,994)
Proceeds from sale of interest in gas properties	—	12,891	—	—	12,891
Net cash used in investing activities	(8,588)	(1,029,285)	(443,592)	—	(1,481,465)
Proceeds from borrowings	900,000	190,000	—	—	1,090,000
Repayments of debt obligations	—	(689,873)	—	—	(689,873)
Restricted cash for convertible debt	—	8,268	—	—	8,268
Debt issuance costs	(19,522)	—	(5,021)	—	(24,543)
Proceeds from conversion of warrants	1,975	—	—	—	1,975
Proceeds from issuance of common stock sold in our IPO, net of offering costs	597,088	—	—	—	597,088
Proceeds from issuance of common stock sold in August 2014 Equity Offering, net of offering costs	196,254	—	—	—	196,254
Proceeds from issuance of common units sold in RMP IPO, net of offering costs	—	—	441,739	—	441,739
Contributions from parent, net	(1,501,511)	—	—	—	—
Net cash provided by financing activities	174,284	943,664	502,960	—	1,620,908
Increase (decrease) in cash	181,835	10,526	32,157	—	224,518
Cash, beginning of year	—	31,408	204	—	31,612
Cash, end of year	\$181,835	\$41,934	\$ 32,361	\$—	\$256,130

Condensed Statement of Cash Flows for the Year Ended December 31, 2013

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Net cash provided by (used in) operating activities	\$—	\$34,428	\$ (756)	\$—	\$33,672
Capital expenditures for natural gas properties	—	(403,920)	(59,208)	—	(463,128)
Capital expenditures for property and equipment	—	(2,259)	—	—	(2,259)
Proceeds from sale of interest in gas properties	—	6,792	—	—	6,792
Net cash used in investing activities	—	(399,387)	(59,208)	—	(458,595)
Proceeds from borrowings	—	435,500	—	—	435,500
Repayments of debt obligations	—	(160,760)	—	—	(160,760)
Restricted cash for convertible debt	—	(8,268)	—	—	(8,268)
Debt issuance costs	—	(12,194)	—	—	(12,194)
Common stock issuance	—	135,815	60,162	—	195,977
Repurchase of common stock	—	(2,267)	—	—	(2,267)
Net cash provided by financing activities	—	387,826	60,162	—	447,988
Increase (decrease) in cash	—	22,867	198	—	23,065
Cash, beginning of year	—	8,541	6	—	8,547
Cash, end of year	\$—	\$31,408	\$ 204	\$—	\$31,612

Condensed Statement of Cash Flows for the Year Ended December 31, 2012

(in thousands)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Net cash used in operating activities	\$—	\$(3,014)	\$ —	\$—	\$(3,014)
Capital expenditures for natural gas properties	—	(109,149)	—	—	(109,149)
Investment in subsidiaries	—	(9,957)	—	—	(9,957)
Capital expenditures for property and equipment	—	(867)	—	—	(867)
Net cash used in investing activities	—	(119,973)	—	—	(119,973)
Proceeds from borrowings	—	44,361	—	—	44,361
Repayments of debt obligations	—	(10,152)	—	—	(10,152)
Debt issuance costs	—	(1,913)	—	—	(1,913)
Common stock issuance	—	96,782	—	—	96,782
Repurchase of common stock	—	(1,133)	—	—	(1,133)
Return of capital	—	(800)	—	—	(800)
Net cash provided by financing activities	—	127,145	—	—	127,145
Increase (decrease) in cash	—	4,158	—	—	4,158
Cash, beginning of year	—	4,383	6	—	4,389
Cash, end of year	\$—	\$8,541	\$ 6	\$—	\$8,547

21. Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for the years ended December 31, 2014 and 2013 is as follows (in thousands):

Year ended December 31, 2014: ⁽¹⁾	First ⁽²⁾ quarter	Second quarter	Third quarter	Fourth ⁽³⁾ quarter
Total operating revenues	\$90,477	\$91,940	\$79,128	\$129,398
Total operating expenses	124,272	67,522	91,453	118,118
Operating income (loss)	(33,795)	24,418	(12,325)	11,280
Net income (loss)	\$129,454	\$(7,917)	\$(6,861)	\$104,360
Net income (loss) attributable to Rice Energy	\$129,454	\$(7,917)	\$(6,861)	\$103,779
Earnings (loss) per share attributable to Rice Energy - basic	\$1.04	\$(0.06)	\$(0.05)	\$0.76
Earnings (loss) per share attributable to Rice Energy - diluted	\$1.03	\$(0.06)	\$(0.05)	\$0.76
Year ended December 31, 2013: ⁽¹⁾	First quarter	Second quarter	Third quarter	Fourth quarter
Total operating revenues	\$13,233	\$23,840	\$23,665	\$27,950
Total operating expenses	10,705	25,833	52,274	27,755
Operating income (loss)	2,528	(1,993)	(28,609)	195
Net income (loss)	\$(6,775)	\$19,586	\$(33,652)	\$(14,935)
Earnings (loss) per share attributable to Rice Energy - basic	\$(0.05)	\$0.24	\$(0.38)	\$(0.25)
Earnings (loss) per share attributable to Rice Energy - diluted	\$(0.05)	\$0.23	\$(0.38)	\$(0.25)

(1) The sum of quarterly data in some cases may not equal the yearly total due to rounding.

Net income attributable to Rice Energy for the three months ended March 31, 2014 included a fair value gain (2) associated with the acquisition of the remaining 50% investment in the Marcellus Joint Venture of \$203.6 million, offset partially by the addition of incentive unit expense of \$69.5 million.

(3) Net income attributable to Rice Energy for the three months ended December 31, 2014 included an unrealized gain on derivative instruments of \$179.1 million.

22. Supplemental Information on Gas-Producing Activities (Unaudited)

Costs incurred for property acquisitions, exploration and development are as follows:

(in thousands)	For the Years Ended December 31,		
	2014	2013	2012
Acquisitions:			
Proved leaseholds	\$439,284	\$—	\$—
Unproved leaseholds	233,185	305,000	47,396
Development costs	734,106	184,217	89,307
Exploration costs:			
Geological and geophysical	4,018	9,951	3,275
Total costs incurred	\$1,410,593	\$499,168	\$139,978

The following table presents the results of operations related to natural gas and oil production:

(in thousands)	For the Years Ended December 31,		
	2014	2013	2012
Revenues	\$359,201	\$87,847	\$26,743
Production costs	67,032	19,712	8,824
Exploration costs	4,018	9,951	3,275
Depreciation, depletion and amortization	151,900	29,808	13,329
Write-down of abandoned leases	—	—	2,253
General and administrative expenses	41,697	5,108	3,050
Income tax expense	38,871	—	—
Results of operations from producing activities	\$55,683	\$23,268	\$(3,988)

Reserve quantity information is as follows:

(in MMcfe)	For the Years Ended December 31,		
	2014	2013 ⁽¹⁾	2012 ⁽¹⁾
Proved developed and undeveloped reserves:			
Beginning of year	382,660	304,272	232,996
Acquisitions	282,391	—	—
Extensions and discoveries	692,239	100,626	176,956
Revision of previous estimates	47,018	757	(96,911)
Production	(97,737)	(22,995)	(8,769)
End of year	1,306,571	382,660	304,272

Proved developed reserves:

End of year	644,149	144,309	61,225
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Proved undeveloped reserves:

End of year	662,422	238,351	243,047
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⁽¹⁾ Reflects the balances for Rice Drilling B. Amounts presented in the table exclude amounts attributable to our Marcellus joint venture for periods prior to the completion of our IPO in January 2014.

Acquisitions

For the year ended December 31, 2014, the Company added 282,391 MMcfe through its purchase of the remaining 50% interest in the Marcellus joint venture in January 2014 and the Greene County Acquisition in August 2014. Amounts presented for the years ended December 31, 2013 and 2012 exclude amounts attributable to our Marcellus joint venture.

Extensions, Discoveries and Other Additions

The Company added 692,239 MMcfe, 100,626 MMcfe and 176,956 MMcfe through its drilling program in the Marcellus Shale and Utica Shale in 2014 and in the Marcellus Shale in 2013 and 2012, respectively.

Revision of Previous Estimates

In 2012, the Company had net negative revisions of 96,991 MMcf, as 32 proved undeveloped locations were removed from its estimate of reserves at December 31, 2011 due primarily to declines in natural gas pricing and changes to the Company's drilling plans with regards to horizontal drilling.

The reserve quantity information is limited to reserves which had been evaluated as of December 31, 2014. Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. Proved undeveloped reserves are expected to be recovered from new wells after substantial development costs are incurred. Netherland, Sewell and Associates, Inc. reviewed 100% of the total net gas proved reserves attributable to the Company's interests and the Company's Marcellus joint venture as of December 31, 2014, 2013 and 2012.

The information presented represents estimates of proved natural gas reserves based on evaluations prepared by the independent petroleum engineering firms of Netherland, Sewell and Associates, Inc. in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. The Company's independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. Since 1961, Netherland, Sewell and Associates, Inc. has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally.

Certain information concerning the assumptions used in computing the standardized measure of proved reserves and their inherent limitations are discussed below. The Company believes such information is essential for a proper understanding and assessment of the data presented. Future cash inflows are computed by applying the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through, respectively, to the period-end quantities of those reserves. Natural gas prices are held constant throughout the lives of the properties.

The assumptions used to compute estimated future net revenues do not necessarily reflect the Company's expectations of actual revenues or costs, or their present worth. In addition, variations from the expected production rates also could result directly or indirectly from factors outside of the Company's control, such as unintentional delays in development, changes in prices or regulatory controls. The standardized measure calculation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, this could affect the amount of cash eventually realized.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing the proved natural gas reserves at the end of the year, based on period-end costs and assuming continuation of existing economic conditions.

An annual discount rate of 10% was used to reflect the timing of the future net cash flows relating to proved natural gas reserves.

Information with respect to the Company's estimated discounted future net cash flows related to its proved natural gas and oil reserves is as follows:

(in thousands)	As of December 31,		
	2014	2013 ⁽¹⁾	2012 ⁽¹⁾
Future cash inflows	\$5,904,380	\$1,496,294	\$869,882
Future production costs	(2,161,926)	(517,101)	(323,855)
Future development costs	(610,179)	(219,879)	(262,084)
Future income tax expense	(745,022)	—	—
Future net cash flows	2,387,253	759,314	283,943
10% annual discount for estimated timing of cash flows	(1,079,499)	(342,150)	(181,725)
Standardized measure of discounted future net cash flows ⁽²⁾	\$1,307,754	\$417,164	\$102,218

⁽¹⁾ Reflects the balances for Rice Drilling B. Amounts presented in the table exclude amounts attributable to our Marcellus joint venture for periods prior to the completion of our IPO in January 2014.

Does not include the effects of income taxes on future revenues at December 31, 2013 and 2012 because those periods reflect the result of Rice Drilling B, our accounting predecessor, which was and currently is a limited liability company not subject to entity-level taxation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income was passed through to Rice Drilling B's equity holders.

⁽²⁾ However, in connection with the closing of our IPO, as a result of the corporate reorganization, the Company became the sole member of Rice Drilling B. The Company is a corporation subject to federal income tax and, as such, its future income taxes will be dependent upon its future taxable income. Therefore, the cumulative effect of future income tax expense for the periods presented was included at December 31, 2014.

For 2014, the reserves for the Company were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2014, adjusted for energy content and a regional price differential. For 2014, this adjusted natural gas price was \$4.52 and the adjusted oil price was \$85.70.

For 2013, the reserves for the Company were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2013, adjusted for energy content and a regional price differential. For 2013, this adjusted natural gas price was \$3.91 per Mcf. We did not have proved reserves for oil in 2013.

For 2012, the reserves for the Company were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2012, adjusted for energy content and a regional price differential. For 2012, this adjusted natural gas price was \$2.86 per Mcf. We did not record reserves for oil in 2012.

The following are the principal sources of changes in the standardized measure of discounted future net cash flows:

(in thousands)	For the Years Ended December 31,		
	2014	2013 ⁽¹⁾	2012 ⁽¹⁾
Balance at beginning of period	\$417,164	\$102,218	\$269,320
Net change in prices and production costs	81,558	101,345	(83,873)
Net change in future development costs	(181,813)	29,336	(31,811)
Natural gas and oil net revenues	(291,023)	(68,135)	(18,376)
Extensions	930,534	114,489	38,937
Acquisitions ⁽²⁾	375,865	—	—
Revisions of previous quantity estimates	37,435	1,133	(108,209)
Previously estimated development costs incurred	62,653	66,894	17,036
Net change in taxes	(436,319)	—	—
Accretion of discount	70,937	10,230	26,932
Changes in timing and other	240,763	59,654	(7,738)
Balance at end of period	\$1,307,754	\$417,164	\$102,218

(1) Reflects the balances for Rice Drilling B. Amounts presented in the table exclude amounts attributable to our Marcellus joint venture for periods prior to the completion of our IPO in January 2014.

(2) Reflects the purchase of the remaining 50% interest in the Marcellus joint venture in January 2014 and the Greene County Acquisition in August 2014.

Does not include the effects of income taxes on future revenues at December 31, 2013 and 2012 because those periods reflect the result of Rice Drilling B, our accounting predecessor, which was and currently is a limited liability company not subject to entity-level taxation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income was passed through to Rice Drilling B's equity holders.

(3) However, in connection with the closing of our IPO, as a result of the corporate reorganization, the Company became the sole member of Rice Drilling B. The Company is a corporation subject to federal income tax and, as such, its future income taxes will be dependent upon its future taxable income. Therefore, the cumulative effect of future income tax expense for the periods presented was included at December 31, 2014.

The information below presents the supplemental information on gas-producing activities for our 50% investment in our Marcellus joint venture for the years ended December 31, 2013 and 2012.

Costs incurred for property acquisitions, exploration and development related to the Company's Marcellus joint venture are as follows (represents Rice Drilling B's proportionate share):

(in thousands)	For the Years Ended December 31,	
	2013	2012
Acquisitions:		
Unproved leaseholds	\$—	\$—
Development costs	46,571	46,725
Exploration costs:		
Geological and geophysical	—	—
Total costs incurred	\$46,571	\$46,725

The following table presents the Company's share of the results of operations related to natural gas production of the Marcellus joint venture (represents Rice Drilling B's proportionate share):

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(in thousands)	For the Years Ended December 31,	
	2013	2012
Revenues	\$45,339	\$13,142
Production costs	12,557	5,435
Impairment of oil and gas properties	—	—
Depreciation, depletion and accretion	12,500	4,702
General and administrative expenses	1,557	986
Results of operations from producing activities	\$18,725	\$2,019

Reserve quantity information is as follows for the Marcellus joint venture (represents Rice Drilling B's proportionate share):

(in thousands)	Natural Gas (MMcf)	
	For the Years Ended December 31,	
	2013	2012
Proved developed and undeveloped reserves:		
Beginning of year	128,118	58,103
Extensions and discoveries	19,812	98,119
Revision of previous estimates	(26,803) (23,808
Production	(11,443) (4,296
End of year	109,684	128,118
Proved developed reserves:		
End of year	52,370	35,013
Proved undeveloped reserves:		
End of year	57,314	93,105

Rice Drilling B's 50% equity interest in the Marcellus joint venture added 19,812 MMcf and 98,119 MMcf through its drilling program in the Marcellus Shale in 2013 and 2012, respectively. In 2013, Rice Drilling B's 50% equity interest in the Marcellus joint venture had net negative revisions of 26,803 MMcf due primarily to performance revisions. In 2012, Rice Drilling B's 50% equity interest in the Marcellus joint venture had net negative revisions of 23,808 MMcf due primarily to declines in natural gas pricing.

Information with respect to the Company's share of the Marcellus joint venture's estimated discounted future net cash flows related to its proved natural gas reserves is as follows:

(in thousands)	As of December 31,	
	2013	2012
Future cash inflows	\$427,167	\$364,157
Future production costs	(132,427) (127,086
Future development costs	(46,344) (86,213
Future net cash flows	248,396	150,858
10% annual discount for estimated timing of cash flows	(102,293) (79,781
Standardized measure of discounted future net cash flows ⁽¹⁾	\$146,103	\$71,077

Does not include the effects of income taxes on future revenues at December 31, 2013 and 2012 because those periods reflect the result of Rice Drilling B, our accounting predecessor, which was and currently is a limited liability company not subject to entity-level taxation. Accordingly, no provision for federal or state corporate (1) income taxes has been provided because taxable income was passed through to Rice Drilling B's equity holders. However, in connection with the closing of our IPO, as a result of the corporate reorganization, the Company became the sole member of Rice Drilling B. The Company is a corporation subject to federal income tax and, as such, its future income taxes will be dependent upon its future taxable income.

For 2013, the reserves for the Marcellus joint venture were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2013, adjusted for energy content and a regional price differential. For 2013, this adjusted gas price was \$3.90 per Mcf.

For 2012, the reserves for the Marcellus joint venture were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2012, adjusted for energy content and a regional price differential. For 2012, this adjusted natural gas price was \$2.84 per Mcf.

The following is for the Marcellus joint venture (represents Rice Drilling B's proportionate share), the principal sources of changes in the standardized measure of discounted future net cash flows:

(in thousands)	For the Years Ended December 31,	
	2013	2012
Balance at beginning of period	\$71,077	\$70,587
Net change in prices and production costs	81,974	(26,855)
Net change in future development costs	2,781	(262)
Natural gas net revenues	(32,782)	(7,707)
Extensions	18,950	38,131
Revisions of previous quantity estimates	(14,752)	(28,923)
Previously estimated development costs incurred	31,253	12,862
Accretion of discount	7,111	7,059
Changes in timing and other	(19,509)	6,185
Balance at end of period	\$146,103	\$71,077

Report of Independent Auditors
The Partners of
Alpha Shale Resources, LP

We have audited the accompanying financial statements of Alpha Shale Resources, LP, which comprise the balance sheets as of December 31, 2013 and 2012, and the related statements of operations, partners' capital and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the 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 involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Alpha Shale Resources, LP at December 31, 2013 and 2012, and the results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania
March 21, 2014

ALPHA SHALE RESOURCES, LP
BALANCE SHEETS

(in thousands)	December 31, 2013	2012
Assets		
Current assets:		
Cash	\$ 11,299	\$ 4,445
Accounts receivable	14,842	5,716
Receivable from affiliate	10	1
Prepaid expenses and other	93	108
Total current assets	26,244	10,270
Gas collateral account	295	295
Proved natural gas properties, net	182,333	114,128
Property and other equipment, net	83	91
Deferred financing costs, net	851	387
Other non-current assets	1,010	—
Total assets	\$ 210,816	\$ 125,171
Liabilities and partners' capital		
Current liabilities:		
Accounts payable	\$ 20,024	\$ 18,953
Royalties payable	6,831	2,082
Accrued interest	16	413
Accrued capital expenditures	1,775	3,489
Other accrued liabilities	2,048	726
Leasehold payables	69	331
Derivative liabilities	2,427	138
Payable to affiliate	2,026	8,538
Total current liabilities	35,216	34,670
Long-term liabilities:		
Long-term debt	75,400	29,200
Leasehold payable	69	—
Other long-term liabilities	712	542
Total liabilities	111,397	64,412
Partners' capital	99,419	60,759
Total liabilities and partners' capital	\$ 210,816	\$ 125,171
See accompanying Notes to Financial Statements.		

ALPHA SHALE RESOURCES, LP
STATEMENTS OF OPERATIONS

(in thousands)	Years Ended December 31,	
	2013	2012
Revenue:		
Natural gas sales	\$90,677	\$26,284
Operating expenses:		
Depreciation, depletion and amortization	25,008	9,411
Gathering, compression and transportation	15,663	6,671
Lease operating	8,193	3,331
Production taxes and impact fees	1,258	869
Loss on impairment of natural gas properties	146	—
General and administrative expenses	3,256	2,058
Total operating expenses	53,524	22,340
Operating income (loss)	37,153	3,944
Other income (expense):		
Other expense	(796) —
Gain (loss) on derivative instruments	3,347	(74)
Amortization of deferred financing costs	(164) (15)
Interest expense	(880) (372)
Total other income (expenses)	1,507	(461)
Net income (loss)	\$38,660	\$3,483
See accompanying Notes to Financial Statements.		

ALPHA SHALE RESOURCES, LP
STATEMENTS OF CASH FLOWS

(in thousands)	Years Ended December 31,	
	2013	2012
Cash flows from operating activities:		
Net income (loss)	\$38,660	\$3,483
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	25,008	9,411
Amortization of deferred financing costs	164	15
Loss on impairment of natural gas properties	146	—
Derivative instruments fair value (gain) loss	(3,347) 74
(Increase) decrease in:		
Accounts receivable	(9,126) (5,067)
Receivable from affiliate	—	25
Gas collateral account	—	(295)
Prepaid expenses and other	15	55
Cash receipts for settled derivatives	4,627	64
Increase (decrease) in:		
Accounts payable	69	347
Royalties payable	4,749	1,734
Other accrued expenses	928	1,050
Payable to affiliate	(6,512) 2,499
Net cash provided by operating activities	55,381	13,395
Cash flows from investing activities:		
Capital expenditures for natural gas properties	(94,099) (63,847)
Capital expenditures for property and other equipment	—	(12)
Net cash used in investing activities	(94,099) (63,859)
Cash flows from financing activities:		
Proceeds from borrowings	46,200	29,200
Debt issuance costs	(628) (402)
Capital contributions	—	20,000
Net cash provided by financing activities	45,572	48,798
Net increase (decrease) in cash	6,854	(1,666)
Cash at the beginning of the year	4,445	6,111
Cash at the end of the year	\$11,299	\$4,445
Supplemental disclosure of non-cash investing and financing activities:		
Capital expenditures for natural gas properties financed by accounts payable	\$19,599	\$18,597
Capital expenditures for natural gas properties financed by other accrued liabilities	1,775	3,489
Capital expenditures for natural gas properties financed by affiliate payable	—	6,038
Natural gas properties financed through deferred payment obligations	138	331
See accompanying Notes to Financial Statements.		

ALPHA SHALE RESOURCES, LP
 STATEMENTS OF PARTNERS' CAPITAL
 YEARS ENDED DECEMBER 31, 2013 AND 2012

(in thousands)	Managing General Partner	Limited Partners	Total
Balance as of December 31, 2011	\$38	\$37,238	\$37,276
Capital contributions	20	19,980	20,000
Net income	3	3,480	3,483
Balance as of December 31, 2012	\$61	\$60,698	\$60,759
Net income	39	38,621	38,660
Balance as of December 31, 2013	\$100	\$99,319	\$99,419
See accompanying Notes to Financial Statements.			

1. Summary of Significant Accounting Policies and Related Matters

Organization and Operations

These financial statements present the activities for Alpha Shale Resources, LP (hereinafter referred to as the “Partnership”). The Partnership was organized as a limited partnership in accordance with the laws of the State of Delaware on February 3, 2010 (date of inception) through funding from its limited partners, Rice Drilling C, LLC (“Rice C”); a wholly-owned subsidiary of Rice Drilling B, LLC (“Rice B”) which in turn is a wholly-owned subsidiary of Rice Energy Inc. (“Rice Energy Inc.”); Foundation PA Coal Company, LLC (“PA Coal”), which is a wholly-owned indirect subsidiary of Alpha Natural Resources, Inc. (“ANR Holdings”); and its managing general partner, Alpha Shale Holdings, LLC (“Holdings”). According to the terms of the limited partnership agreement, revenues, costs and cash distributions of the Partnership are allocated 49.95% each to PA Coal and Rice and 0.10% to Holdings.

The Partnership is engaged primarily in the acquisition, exploration, development, production and sale of natural gas in the Marcellus Shale region of southwestern Pennsylvania.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates and changes in these estimates are recorded when known.

Revenue Recognition

Sales of natural gas are recognized when natural gas has 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. Natural gas is sold by the Partnership under contract with the Partnership’s natural gas marketer and only current customer. Pricing provisions are tied to the Platts Gas Daily market prices.

Cash

The Partnership maintains cash at financial institutions which may at times exceed federally insured amounts and which may at times significantly exceed balance sheet amounts due to outstanding checks. The Partnership has no other accounts that are considered cash equivalents.

Accounts Receivable

Accounts receivable are primarily from the Partnership’s sole gas marketer. The Partnership extends credit to parties in the normal course of business based upon management’s assessment of their creditworthiness. A valuation allowance is provided for those accounts for which collection is estimated as doubtful; uncollectible accounts are written off and charged against the allowance. In estimating the allowance, management considers, among other things, how recently and how frequently payments have been received and the financial position of the party. There was no allowance recorded for any of the periods presented in the financial statements.

(in thousands)	December 31,	
	2013	2012
Natural gas sales	\$ 14,458	\$ 5,570
Other	384	146
Total accounts receivable	\$ 14,842	\$ 5,716

Natural Gas Properties

The Partnership uses the successful efforts method of accounting for gas-producing activities. Costs to acquire mineral interests in natural gas properties, to drill and equip exploratory wells that result in proved reserves are capitalized. Costs to drill exploratory wells that do not identify proved reserves as well as geological and geophysical costs and cost of carrying and retaining unproved properties are expensed.

Unproved natural gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Management determined that no impairment allowance was necessary as of December 31, 2013 and 2012. Capitalized costs of producing natural gas properties and support equipment directly related to such properties, after considering estimated residual salvage values, are depreciated and depleted by the unit-of-production method. Support equipment and other property and equipment not directly related to natural gas properties are depreciated over their estimated useful lives.

The Partnership assesses its proved natural gas properties for possible impairment on an annual basis, as events or changes in circumstances indicate that the carrying amount of an asset might not be recoverable. Management determined that no impairment allowance was necessary as of December 31, 2013 and 2012. During 2013, it was decided by the Operating Committee of the Partnership not to complete three vertical wells that had previously commenced drilling, as such an impairment charge of \$0.1 million was recorded during the year ended December 31, 2013. There was no impairment charge during the year ended December 31, 2012.

Partnership estimates of proved reserves are based on quantities of natural gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic conditions. External engineers prepare the annual reserve and economic evaluation of all properties on a well-by-well basis. Additionally, the Partnership adjusts natural gas reserves for major well rework or abandonment during the year as needed. The process of estimating and evaluating natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates represent the Partnership's most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect the Partnership's depreciation, depletion and amortization expense, as well as its impairment assessment of proved properties, a change in the Partnership's estimated reserves could have a material effect on the Partnership's net income or loss.

On the sale of an entire interest in an unproved property for cash, a gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained unless the proceeds received are in excess of the cost basis which would result in gain on sale.

Interest

The Partnership capitalizes interest on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use. The following table summarizes the components of the Partnership's interest incurred for the year indicated (in thousands):

	Year Ended December 31,	
	2013	2012
Interest capitalized	\$216	\$143
Interest expensed	880	372
Total incurred	\$1,096	\$515

Property and Other Equipment

Property and other equipment is recorded at cost and is being depreciated over estimated useful lives of five to fifteen years on a straight-line basis. Accumulated depreciation was \$18 thousand and \$9 thousand at December 31, 2013 and 2012, respectively. Depreciation expense was \$9 thousand and \$8 thousand for the years ended December 31, 2013 and 2012, respectively, and is included in depreciation, depletion and amortization expense in the accompanying

statements of operations.

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Long-Lived Assets

Long-lived assets to be held and used or disposed of other than by sale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used or disposed other than by sale are recognized based on the fair value of the asset. Long-lived assets to be disposed of by sale are reported at the lower of their carrying amount or fair value less selling costs.

Deferred Financing Costs

Deferred financing costs are amortized on a straight-line basis over the term of the related agreement. Accumulated amortization was \$0.2 million and \$15 thousand at December 31, 2013 and 2012, respectively. Amortization expense was \$0.2 million and \$15 thousand for the years ended December 31, 2013 and 2012, respectively. The annual amortization of deferred financing costs for years subsequent to December 31, 2013 is expected to be \$0.3 million in each of the years through 2016 and \$0.2 million in 2017.

Asset Retirement Obligations

The Partnership records the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. For gas properties, this is the period in which a gas well is acquired or drilled. The Partnership's retirement obligations relate to the abandonment of gas-producing facilities and include costs to dismantle and relocate or dispose of the production platforms, gathering systems, wells and related structures. Estimates are based on historical experience in plugging and abandoning wells and estimated remaining lives of those wells based on reserve estimates. When a new liability is recorded, the Partnership capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the capitalized cost is depreciated over the units of production basis.

Lease Obligations

The Partnership leases drilling rights under agreements which expire at various times. As of December 31, 2013, future minimum lease payments under these agreements expected to be paid during 2014 and 2015 are \$0.1 million and \$0.1 million, respectively, and are included as leasehold payables in the accompanying balance sheets.

Income Taxes

The Partnership is treated as a limited partnership for federal and state income tax purposes. Consequently, the Partnership is not subject to income taxes; instead its partners include the income in their tax returns.

Reclassifications

Certain reclassifications have been made to prior periods' financial information related to accrued interest, other accrued liabilities and derivative liabilities to conform to the 2013 presentation.

2. Capitalized Costs Relating to Natural Gas-Producing Activities

Proved and unproved capitalized costs related to the Partnership's natural gas-producing activities are as follows (in thousands):

	December 31,	
	2013	2012
Capitalized costs:		
Proved, producing properties	\$173,117	\$50,437
Proved, non-producing properties	45,861	75,338
Total	218,978	125,775
Accumulated depreciation, depletion and amortization	36,645	11,647
Net capitalized costs	\$182,333	\$114,128

3. Long-Term Debt

The Partnership had long-term debt outstanding as follows (in thousands):

Description	December 31,	
	2013	2012
Long-term Debt		
Wells Fargo Credit Facility	\$75,400	\$29,200
Total long-term debt	\$75,400	\$29,200
Wells Fargo Credit Facility		

On September 7, 2012, the Partnership entered into a credit agreement (“Wells Fargo Credit Facility”) with Wells Fargo Bank, N.A. (“Wells Fargo”). The maximum credit amount allowed under the promissory note agreement is \$200.0 million, payable at maturity with interest only due in monthly installments at the higher of the prime rate, the federal funds rate plus 0.5% or the adjusted LIBOR plus 1%; all unpaid balances are due September 7, 2017; secured by substantially all assets of the Partnership. The weighted average interest rate was 2.42% as of December 31, 2013. As of December 31, 2013, the Partnership issued letters of credit of \$10.4 million with Wells Fargo as required by the Partnership’s natural gas marketer. The borrowing base as of December 31, 2013 was \$145.0 million with approximately \$59.2 million undrawn at that date. This credit facility was repaid using proceeds from the Rice Energy Inc. IPO during the first quarter of 2014.

The Wells Fargo Credit Facility provides for borrowings to be used for the purpose of funding capital expenditures related to the Partnership’s drilling program, providing working capital for lease acquisitions, exploration and production operations, and development (including the drilling and completion of producing wells), and for general business purposes, including fees and expenses. The Wells Fargo Credit Facility is subject to a maximum borrowing base equal to the maximum value, for credit purposes, of the subject properties as determined by Wells Fargo in accordance with its customary lending practices. The borrowing base is determined by the lenders on a quarterly basis and such determination is primarily based upon the value of the Partnership’s proved developed reserves. If the lenders were to decrease the borrowing base below the amounts outstanding under the facility, the Partnership would have to repay these amounts within 30 days, repay these amounts in six monthly installments, or add sufficient collateral value.

The Wells Fargo Credit Facility is subject to certain covenants which are ordinary to such credit facilities and include, among other things, minimum financial ratios, restrictions as to additional debt and changes to the Partnership’s structure. The Partnership was in compliance with such covenants and ratios as of December 31, 2013.

Interest paid in cash was \$1.5 million and \$0.1 million for the years ended December 31, 2013 and 2012, respectively. See Note 1 for information on capitalized interest.

4. Fair Value of Financial Instruments

The Partnership determines fair value on a recurring basis for its amounts related to its derivative instruments as the amounts are required to be recorded at fair value each reporting period. Fair value is based on quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use as inputs market-based parameters, including but not limited to forward curves, discount rates, broker quotes, volatilities, and nonperformance risk.

The Partnership has categorized its fair value measurements into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). All of the Partnership’s fair value measurements are included in Level 2. Since the adoption of fair value accounting, the Partnership has not made any changes to its classification of financial instruments in each category.

Items included in Level 2 are valued using management’s best estimate of fair value corroborated by third-party quotes.

The following items were measured at fair value on a recurring basis during the period (refer to Note 7 for details relating to derivative instruments) (in thousands):

Description	December 31, 2013	Fair Value Measurements at Reporting Date Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Derivative Instruments, at fair value	\$1,010	\$—	\$1,010	\$—
Total assets	\$1,010	\$—	\$1,010	\$—
Liabilities:				
Derivative Instruments, at fair value	\$2,427	\$—	\$2,427	\$—
Total liabilities	\$2,427	\$—	\$2,427	\$—

Description	December 31, 2012	Fair Value Measurements at Reporting Date Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities:				
Derivative Instruments, at fair value	\$138	\$—	\$138	\$—
Total liabilities	\$138	\$—	\$138	\$—

The carrying amount of cash, receivables and accounts payable approximate their fair value due to the short-term nature of such instruments.

The estimated fair value of long-term debt on the balance sheet at December 31, 2012 is shown in the table below (refer to Note 3 for details relating to the borrowing arrangements (in thousands)). The fair value was estimated using Level 3 inputs based on rates reflective of the remaining maturity as well as the Partnership's financial position.

Description	December 31,	
	2013	2012
Long-term debt, at fair value:		
Wells Fargo Credit Facility	\$75,400	\$29,200
Total	\$75,400	\$29,200

5. Asset Retirement Obligations

The Partnership is subject to certain legal requirements which result in recognition of a liability related to the obligation to incur future plugging and abandonment costs. The Partnership records a liability for such asset retirement obligations and capitalizes a corresponding amount for asset retirement costs. The liability is estimated using the present value of expected future cash flows, adjusted for inflation and discounted at the Partnership's credit adjusted risk-free rate. No wells were plugged or abandoned during 2012, nor were there any changes to assumptions. A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations for the years ended December 31, 2013 and 2012 is as follows (in thousands):

Balance at December 31, 2011	\$ 307
Liabilities incurred	138
Accretion expense	97
Balance at December 31, 2012	\$ 542
Liabilities incurred	110
Accretion expense	60
Balance at December 31, 2013	\$ 712

6. Partners' Capital

The Partnership consists of three partners: Holdings, which is the managing general partner, and PA Coal and Rice C, the limited partners. The Partnership authorized and issued 10,000 units during 2010. In February 2010, Holdings contributed \$6 thousand for 10 units, or a 0.10% ownership, and PA Coal and Rice each contributed \$3.0 million for 4,995 shares, or 49.95% ownership each. In 2012 and 2013 the managing partner contributed an additional \$20 thousand and \$39 thousand, respectively, and the limited partners contributed an additional \$20.0 million and \$38.6 million, respectively.

Since inception, the three partners have continued to make additional contributions into the Partnership, in accordance with ownership percentages, and no additional units were issued as depicted on the statements of changes in partners' capital.

7. Derivative Instruments

The Partnership uses derivative commodity instruments that are placed with major financial institutions whose creditworthiness is regularly monitored. Our derivative counterparties share in the Credit Agreement collateral. The Partnership's derivative commodity instruments have not been designated as hedges for accounting purposes; therefore, all gains and losses were recognized in income currently. As of December 31, 2013, the Partnership entered into derivative instruments with Wells Fargo Bank, N.A. and Bank of Montreal fixing the price it receives for natural gas through December 31, 2017, as summarized in the following table:

Swap Contract Expiration	MMbtu/day	Weighted Average Price
2014	83,648	\$4.120
2015	33,240	\$4.173
2016	30,000	\$4.127
2017	30,000	\$4.127
Collar Contract Expiration	MMbtu/day	Floor/Ceiling
2015	25,000	\$3.750/\$5.000

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The following is a summary of the Partnership's derivative instruments, which are recorded in the balance sheet as of December 31, 2013 and 2012 (in thousands):

	December 31, 2013	December 31, 2012
Current derivative assets	\$1,140	\$141
Long-term derivative assets	1,577	—
	\$2,717	\$141
Current derivative liabilities	\$3,567	\$279
Long-term derivative liabilities	567	—
	\$4,134	\$279
Net current value of derivative liabilities	\$(2,427) \$(138
Net long-term value of derivative assets	\$1,010	\$—

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets for the periods presented, all at fair value:

Description	December 31, 2013		
	Gross Amounts of Recognized Assets	Gross Amounts Offset on Balance Sheet	Net Amounts of Assets (Liabilities) on Balance Sheet
Derivative assets	\$3,719	\$(1,002) \$2,717
Derivative liabilities	\$736	\$(4,870) \$(4,134
Description	December 31, 2012		
	Gross Amounts of Recognized Assets	Gross Amounts Offset on Balance Sheet	Net Amounts of Assets (Liabilities) on Balance Sheet
Derivative assets	\$324	\$(183) \$141
Derivative liabilities	\$122	\$(401) \$(279

Both realized and unrealized gains and losses are recorded as a gain or loss on derivatives in the consolidated statement of operations under other income/expense. Unrealized losses were \$1.3 million and \$0.1 million for the years ended December 31, 2013 and 2012, respectively. Realized gains related to contract settlements were \$4.6 million and \$0.1 million for the years ended December 31, 2013 and 2012, respectively.

8. Commitments and Contingencies

The Partnership is involved in various litigation matters arising in the normal course of business. Management is not aware of any actions that are expected to have a material adverse effect on its financial position or results of operations.

The Partnership has drilling commitments which management expects to meet in the ordinary course of business.

9. Related-Party Transactions

During the years ended December 31, 2013 and 2012, the Partnership was billed for management services provided in the amount of \$2.1 million and \$1.3 million, respectively, which is included with general and administrative expenses on the statements of operations. As of December 31, 2013 and 2012, \$2.0 million and \$8.5 million, respectively, of costs were due to related entities and recorded as payable to affiliate on the balance sheets. Included in the 2013 amount are management service fees as described above as well as fees for gathering and transportation incurred by the Partnership that were billed to related parties. Included in the 2012 amount is \$6.0 million relating to capitalized costs that were approved to be contributed from related entities.

Payments totaling \$1.2 million \$0.5 million were made during the years ended December 31, 2013 and 2012, respectively, to Geological Engineering Services, Inc. ("GES") in respect of consultancy services. GES is a drilling and completion engineering consulting company specializing in unconventional reservoirs like the Marcellus Shale. John P.

LaVelle, Rice Energy's Vice President of Drilling, served as president of GES from February 1994 until February 2010. There were no amounts outstanding between the Partnership and GES as of any period presented.

10. Subsequent Events

Transaction Agreement

On January 29, 2014, pursuant to the Transaction Agreement between Rice Energy Inc., Rice C and Alpha Holdings dated as of December 6, 2013 (the "Transaction Agreement"), Rice Energy Inc. completed their acquisition of Alpha Holdings' 50% interest in the Partnership in exchange for total consideration of \$300 million, consisting of \$100 million of cash and the issuance to Alpha Holdings of 9,523,810 shares of Rice Energy Inc. common stock. Subsequent events have been considered for disclosure and recognition through March 21, 2014, the same date the financial statements were available to be issued.

11. Supplemental Information on Gas-Producing Activities (Unaudited)

Costs incurred for property acquisitions, exploration and development for the years ended December 31, 2013 and 2012 are as follows (in thousands):

	For the Years Ended December 31,	
	2013	2012
Acquisitions:		
Unproved leaseholds	\$—	\$—
Development costs	93,142	93,450
Exploration costs:		
Geological and geophysical	—	—
Total costs incurred	\$93,142	\$93,450

The following table presents the results of operations related to natural gas production (in thousands):

	For the Years Ended December 31,	
	2013	2012
Revenues	\$90,677	\$26,284
Production costs	25,114	10,872
Impairment of gas properties	—	—
Depreciation, depletion and amortization	25,000	9,404
General and administrative expenses	3,114	1,972
Results of operations from producing activities	\$37,449	\$4,036

Reserve quantity information for the years ended December 31, 2013 and 2012 are as follows (in thousands):

	2013	2012
Proved developed and undeveloped reserves:		
Beginning of year	256,236	116,206
Extensions and discoveries	39,623	196,238
Revision of previous estimates	(53,605)	(47,616)
Production	(22,886)	(8,592)
End of year	219,368	256,236
Proved developed reserves:		
End of year	104,741	70,026
Proved developed reserves:		
End of year	114,627	186,210

The Partnership added 39,623 MMcf and 196,238 MMcf through its drilling program in the Marcellus Shale in 2013 and 2012, respectively. In 2013, the Partnership had net negative revisions of 53,605 MMcf due primarily to performance revisions. In 2012, the Partnership had net negative revisions of 47,616 MMcf due primarily to declines in natural gas pricing.

Information with respect to estimated discounted future net cash flows related to its proved natural gas reserves as of December 31, is as follows (in thousands):

	2013	2012
Future cash inflows	\$854,334	\$728,314
Future production costs	(264,853)	(254,172)
Future development costs	(92,689)	(172,426)
Future net cash flows	496,792	301,716
10% annual discount for estimated timing of cash flows	(204,586)	(159,562)
Standardized measure of discounted future net cash flows	\$292,206	\$142,154

For 2013, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2013, adjusted for energy content and a regional price differential. For 2013, this adjusted gas price was \$3.90 per Mcf.

For 2012, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2012, adjusted for energy content and a regional price differential. For 2012, this adjusted gas price was \$2.84 per Mcf.

The following is the principal sources of changes in the standardized measure of discounted future net cash flows (in thousands):

	2013	2012
Balance at beginning of period	\$142,154	\$141,174
Net change in prices and production costs	163,948	(53,710)
Net change in future development costs	5,563	(524)
Natural gas net revenues	(65,563)	(15,414)
Extensions	37,901	76,262
Revisions of previous quantity estimates	(29,504)	(57,846)
Previously estimated development costs incurred	62,507	25,724
Accretion of discount	14,222	14,118
Changes in timing and other	(39,022)	12,370
Balance at end of period	\$292,206	\$142,154

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended (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 Annual Report. Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Based upon that evaluation, our principal executive officer and principal financial officer concluded that their disclosure controls and procedures were effective as of December 31, 2014.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting, other than continued implementation and refinement of the controls necessary to remediate the previous year’s material weakness.

Management’s Annual Report on Internal Control Over Financial Reporting

The management of Rice Energy is responsible for establishing and maintaining adequate internal control over financial reporting for us as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Our internal control over financial reporting includes those policies and procedures that:

- (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of the assets;
- (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of 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

(iii) 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, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect misstatements. Further, because of changes in conditions, effectiveness of internal controls over financial reporting may vary over time.

Under the supervision of, and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control-Integrated Framework in 1992, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management of Rice Energy concluded that their internal control over financial reporting was effective as of December 31, 2014.

Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit us to provide only management's report in this Annual Report on Form 10-K. Therefore, this Annual Report on Form 10-K does not include such an attestation.

Remediation of Prior Year Material Weakness

Prior to the completion of our IPO, we were a private company with limited accounting personnel to adequately execute our accounting processes and other supervisory resources with which to address our internal control over financial reporting. In addition, our Marcellus joint venture historically relied on our accounting personnel for its accounting processes. We and our Marcellus joint venture had not maintained effective control environments in that the design and execution of our controls had not consistently resulted in effective review and supervision by individuals with financial reporting oversight roles. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare the financial statements of us and our Marcellus joint venture. We concluded that these control deficiencies constituted a material weakness in our control environment and in the control environment of our Marcellus joint venture as of December 31, 2012 and December 31, 2013. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that a reasonable possibility exists that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis.

To address these control deficiencies, we implemented additional analysis and reconciliation procedures and increased the levels of review and approval. In addition, we hired additional accounting and financial reporting staff. These hires were made to allow for additional preparation and review time during our monthly accounting close process.

Additionally, we comprehensively documented and analyzed our system of internal control over financial reporting in preparation for our first management report on internal control over financial reporting required in connection with this Annual Report. Management performed testing to validate the operating effectiveness of these controls. In reviewing the results from this testing, management concluded that the above referenced material weakness in internal control over financial reporting has been remediated as of December 31, 2014.

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. We expect 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. We expect 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. We expect 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. We expect 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 Accountant Fees and Services

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect 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 Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The exhibits listed on the accompanying index to exhibits (pages 156 through 160) are filed as part of this Annual Report on Form 10-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.

RICE ENERGY INC.

By: /s/ Daniel J. Rice IV
Daniel J. Rice IV
Director, Chief Executive Officer
March 13, 2015

Pursuant to the requirements of the Securities 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.

Name	Title	Date
/s/ Daniel J. Rice IV Daniel J. Rice IV	Director, Chief Executive Officer (Principal Executive Officer)	March 13, 2015
/s/ Toby Z. Rice Toby Z. Rice	Director, President and Chief Operating Officer	March 13, 2015
/s/ Grayson T. Lisenby Grayson T. Lisenby	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 13, 2015
/s/ James W. Rogers James W. Rogers	Senior Vice President, Chief Accounting & Administrative Officer, Treasurer (Principal Accounting Officer)	March 13, 2015
/s/ Robert F. Vagt Robert F. Vagt	Director	March 13, 2015
/s/ Daniel J. Rice III Daniel J. Rice III	Director	March 13, 2015
/s/ Scott A. Gieselman Scott A. Gieselman	Director	March 13, 2015
/s/ James W. Christmas James W. Christmas	Director	March 13, 2015
/s/ Steven C. Dixon Steven C. Dixon	Director	March 13, 2015

Index to Exhibits

Exhibits are incorporated by reference or are filed with this report as indicated below (numbered in accordance with Item 601 of Regulation S-K).

Exhibit No.	Description
2.1***	Purchase and Sale Agreement, among M3 Appalachia Gathering, LLC, as seller, Rice Poseidon Midstream LLC, as Buyer, dated as of February 12, 2014 (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 14, 2014).
2.2	Purchase and Sale Agreement, dated July 11, 2014, by and among Rice Drilling B LLC, Chesapeake Appalachia, L.L.C. and Statoil USA Onshore Properties Inc. (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on August 7, 2014).
3.1	Amended and Restated Certificate of Incorporation of Rice Energy Inc. (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
3.2	Amended and Restated Bylaws of Rice Energy Inc. (incorporated by reference to Exhibit 3.2 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (File No. 133-192894) filed with the Commission on January 13, 2014).
4.2	Registration Rights Agreement, dated as of January 29, 2014, by and among Rice Energy Inc., Rice Energy Holdings LLC, Rice Energy Family Holdings, LP, NGP Rice Holdings LLC and Foundation PA Coal Company, LLC (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
4.3	Stockholders' Agreement, dated as of January 29, 2014, by and among Rice Energy Inc., Rice Energy Holdings LLC, Rice Energy Family Holdings, LP, NGP Rice Holdings LLC and Alpha Natural Resources, Inc. (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
4.4	First Amendment to Stockholders' Agreement, dated as of January 29, 2014, by and among Rice Energy, Inc., Rice Energy Holdings, LLC, NGP Rice Holdings, LLC and Alpha Natural Resources, Inc. (incorporated by reference as Exhibit 4.5 of the Company's Quarterly Report on Form 10-Q (File No. 001-36273) filed with the Commission on August 11, 2014).
4.5	Indenture, dated as of April 25, 2014, by and among Rice Energy Inc., the several guarantors named therein and Wells Fargo Bank, National Association, as trustee. (incorporated by reference as Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on April 29, 2014).
4.6	Supplemental Indenture, dated as of November 10, 2014, by and among Rice Energy Inc., the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.6 of the Company's Registration Statement on Form S-4 (File No. 333-200693) filed with the Commission on December 3, 2014).
4.7	Form of 6.250% Senior Note due 2022 (included as Exhibit A to Exhibit 4.5).
4.8	Registration Rights Agreement, dated as of April 25, 2014, by and among Rice Energy Inc., the several guarantors named therein and Barclays Capital Inc. as representative of the initial purchasers named therein (incorporated by reference as Exhibit 4.3 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on April 29, 2014).
4.9	Agreement of Assignment and Assumption, dated as of November 17, 2014, by and between Rice Energy Family Holdings, LP and Rice Energy Irrevocable Trust (incorporated by reference to Exhibit 4 of the Company's Schedule 13D/A (CUSIP No. 762760106) filed with the Commission on November

26, 2014).

10.1 Senior Secured Term Loan Credit Agreement, dated as of April 25, 2013, among Rice Drilling B LLC, as borrower, Barclays Bank PLC, as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.10 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on October 3, 2013).

10.2 Third Amended and Restated Credit Agreement, dated as of April 10, 2014, among Rice Energy Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders and other parties thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on April 11, 2014).

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- 10.3 First Amendment to Third Amended and Restated Credit Agreement, dated as of October 20, 2014, among Rice Energy Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders and other parties thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on October 22, 2014).
- 10.4 Limited Consent and Second Amendment to Third Amended and Restated Credit Agreement, dated as of February 6, 2015, among Rice Energy Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders and other parties thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 12, 2015).
- 10.5 Credit Agreement, dated as of December 22, 2014, among Rice Midstream Partners LP, as Parent Guarantor, Rice Midstream OpCo LLC, as Borrower, Wells Fargo Bank, National Association, as administrative agent, certain lenders party thereto and the other parties thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on December 23, 2014).
- 10.6 Credit Agreement, dated as of December 22, 2014 among Rice Midstream Holdings LLC, as Borrower, Wells Fargo Bank, National Association, as administrative agent, certain lenders party thereto and the other parties thereto (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on December 23, 2014).
- 10.7 Master Reorganization Agreement, dated as of January 23, 2014, by and among Rice Energy Family Holdings, LP, NGP RE Holdings, L.L.C., NGP RE Holdings II, L.L.C., Daniel J. Rice III, Rice Drilling B LLC, Rice Merger LLC, Rice Energy Appalachia, LLC, each of the persons holding incentive units representing interests in Rice Energy Appalachia, LLC, Rice Energy Inc., Rice Energy Holdings LLC, and NGP Rice Holdings LLC (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on January 29, 2014).
- 10.8 Agreement and Plan of Merger of Rice Merger LLC with and into Rice Drilling B LLC (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on January 29, 2014).
- 10.9 Transaction Agreement by and among Rice Energy Inc., Rice Drilling C LLC and Foundation PA Coal Company, LLC, dated as of December 6, 2013 (incorporated by reference to Exhibit 10.8 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on December 16, 2013).
- 10.10† Amended and Restated Liability Company Agreement of Rice Energy Appalachia, LLC (incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on January 8, 2014).
- 10.11† Amended and Restated Liability Company Agreement of Rice Energy Holdings LLC (incorporated by reference to Exhibit 10.23 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.12† Amended and Restated Liability Company Agreement of NGP Rice Holdings LLC (incorporated by reference to Exhibit 10.24 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.13† Employment Agreement (Daniel J. Rice IV) (incorporated by reference to Exhibit 10.17 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.14† Employment Agreement (Toby Z. Rice) (incorporated by reference to Exhibit 10.18 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.15† Employment Agreement (Derek A. Rice) (incorporated by reference to Exhibit 10.19 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.16† Employment Agreement (Grayson T. Lisenby) (incorporated by reference to Exhibit 10.20 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4,

2014).
10.17† Employment Agreement (James W. Rogers) (incorporated by reference to Exhibit 10.21 of the
Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4,
2014).

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- 10.18† Employment Agreement (William E. Jordan) (incorporated by reference to Exhibit 10.22 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.19*† Employment Agreement (Robert R. Wingo).
Indemnification Agreement (Daniel J. Rice IV) (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.20† Indemnification Agreement (Toby Z. Rice) (incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.21† Indemnification Agreement (Derek A. Rice) (incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.22† Indemnification Agreement (Grayson T. Lisenby) (incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.23† Indemnification Agreement (James W. Rogers) (incorporated by reference to Exhibit 10.6 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.24† Indemnification Agreement (William E. Jordan) (incorporated by reference to Exhibit 10.7 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.25† Indemnification Agreement (Daniel J. Rice III) (incorporated by reference to Exhibit 10.8 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.26† Indemnification Agreement (Scott A. Gieselman) (incorporated by reference to Exhibit 10.9 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.27† Indemnification Agreement (Kevin S. Crutchfield) (incorporated by reference to Exhibit 10.10 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.28† Indemnification Agreement (James W. Christmas) (incorporated by reference to Exhibit 10.11 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.29† Indemnification Agreement (Chris G. Carter) (incorporated by reference to Exhibit 10.12 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.30† Indemnification Agreement (Robert F. Vagt) (incorporated by reference to Exhibit 10.13 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on February 4, 2014).
- 10.31† Indemnification Agreement, dated as of August 8, 2014, by and among the Company, Alpha Natural Resources, Inc. and Kevin S. Crutchfield (incorporated by reference to Exhibit 10.5 of the Company's Quarterly Report on Form 10-Q (File No. 001-36273) filed with the Commission on August 11, 2014).
- 10.32† Indemnification Agreement (Steven C. Dixon) (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on December 9, 2014).
- 10.33† Indemnification Agreement (Robert R. Wingo).
Rice Energy Management Bonus Plan (incorporated by reference to Exhibit 10.14 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on November 12, 2013).
- 10.34*†
- 10.35†

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10.36† Form of Restricted Stock Unit Agreement (Employees) (incorporated by reference to Exhibit 10.13 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on December 16, 2013).

10.37† Form of Restricted Stock Unit Agreement (Directors) (incorporated by reference to Exhibit 10.19 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on January 8, 2014).

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- 10.38† Amended and Restated Rice Energy Inc. 2014 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-36273) filed with the Commission on August 11, 2014).
- 10.39† Form of Performance Stock Unit (PSU) Agreement (incorporated by reference to Exhibit 10.44 of the Company's Registration Statement on Form S-1 (File No. 333-197266) filed with the Commission on July 7, 2014).
- 10.40 Form of Senior Subordinated Convertible Debentures due 2014 (incorporated by reference to Exhibit 10.14 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on December 16, 2013).
- 10.41 Amendment, Consent and Parent Guaranty to Senior Subordinated Convertible Debentures due 2014 (incorporated by reference to Exhibit 10.21 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on January 8, 2014).
- 10.42 Form of Warrant Agreement (incorporated by reference to Exhibit 10.16 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on December 16, 2013).
- 10.43 Form of Bonus Warrant Agreement (incorporated by reference to Exhibit 10.17 of the Company's Registration Statement on Form S-1 (File No. 333-192894) filed with the Commission on December 16, 2013).
- 10.44 Form of Amended and Restated Warrant to Purchase Shares of Common Stock (incorporated by reference to Exhibit 10.41 of the Company's Annual Report on Form 10-K (File No. 001-36273) filed with the Commission on March 21, 2014).
- 10.45 Form of Amended and Restated Bonus Warrant to Purchase Shares of Common Stock (incorporated by reference to Exhibit 10.42 of the Company's Annual Report on Form 10-K (File No. 001-36273) filed with the Commission on March 21, 2014).
- 10.46 Purchase Agreement dated as of April 16, 2014 among the Company, the Guarantors and Barclays Capital Inc., as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on April 21, 2014).
- 10.47 Contribution Agreement, dated as of December 22, 2014, by and among Rice Midstream Partners LP, Rice Midstream Management LLC, Rice Poseidon Midstream LLC, Rice Midstream Holdings LLC and Rice Energy Inc. (incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on December 23, 2014).
- 10.48 Omnibus Agreement, dated as of December 22, 2014, by and between Rice Midstream Partners LP, Rice Midstream Management LLC, Rice Midstream Holdings LLC and Rice Energy Inc. (incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on December 23, 2014).
- 10.49 Gas Gathering and Compression Agreement, dated as of December 22, 2014, by and between Rice Drilling B LLC, Rice Midstream Partners LP and Alpha Shale Resources, LP (incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K (File No. 001-36273) filed with the Commission on December 23, 2014).
- 21.1* List of Subsidiaries of Rice Energy Inc.
- 23.1* Consent of Ernst & Young LLP (Rice Energy Inc.).
- 23.2* Consent of Ernst & Young LLP (Alpha Shale Resources, LP).
- 23.3* Consent of Netherland, Sewell and Associates, Inc.
- 31.1* Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Executive Officer.
- 31.2* Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Financial Officer.
- 32.1** Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.

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- 32.2** Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
- 99.1* Netherland, Sewell and Associates, Inc., Summary of Reserves at December 31, 2014.
- 101.INS* XBRL Instance Document.
- 101.SCH* XBRL Schema Document.

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101.CAL* XBRL Calculation Linkbase Document.
101.DEF* XBRL Definition Linkbase Document.
101.LAB* XBRL Labels Linkbase Document.
101.PRE* XBRL Presentation Linkbase Document.

* Filed herewith.

Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this Annual Report on Form 10-K and not “filed” as part of such report for purposes of Section 18 of the Securities Exchange Act, as amended, or otherwise subject to the liability of Section 18 of the Securities Exchange Act, as amended, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Exchange Act of 1933, as amended, except to the extent that the registrant specifically incorporates it by reference.

** The schedules to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such schedules to the Securities and Exchange Commission upon request.

*** Management contract or compensatory plan or agreement.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

“Bcf.” One billion cubic feet of natural gas.

“Bcfe.” One billion cubic feet of natural gas equivalent, determined by using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate of natural gas liquids.

“Btu.” One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree of Fahrenheit.

“Basin.” A large natural depression on the earth’s surface in which sediments generally brought by water accumulate.

“Completion.” The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“DD&A.” Depreciation, depletion, amortization and accretion.

“Delineation.” The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

“Developed acreage.” The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

“Drilling locations.” Total net resource play locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

“Dry gas.” A natural gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.

“Dry hole.” A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

“EUR.” Estimated ultimate recovery.

“Exploratory well.” A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

“Field.” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“Formation.” A layer of rock which has distinct characteristics that differs from nearby rock.

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

“Net drilling locations.” Net drilling locations are those drilling locations identified by management based on the following criteria:

Undeveloped Net Marcellus Locations – We assume these locations have 7,000 foot laterals and 750 foot spacing between wells which yields approximately 121 acre spacing. In the Marcellus, we apply a 20% risking factor to our net acreage to account for inefficient unitization and the risk associated with our inability to force pool in Pennsylvania. As of December 31, 2014, we had 64,000 net acres in the Marcellus which results in 356 undeveloped net locations.

Undeveloped Net Greene County Locations – We assume these locations have 7,000 foot laterals and 750 foot spacing between wells which yields approximately 121 acre spacing. In Greene County, we apply a 20% risking factor to our net acreage to account for inefficient unitization and the risk associated with our inability to force pool in Pennsylvania. As of December 31, 2014, we had 22,000 net acres in Greene County which results in 139 undeveloped net locations.

Undeveloped Net Upper Devonian Locations - We assume these locations have 7,000 foot laterals and 1,000 foot spacing between wells which yields approximately 161 acre spacing. In the Upper Devonian, we apply a 20% risking factor to our net acreage to account for inefficient unitization and the risk associated with our inability to force pool in Pennsylvania. As of December 31, 2014, we had 77,000 net acres prospective for the Upper Devonian which results in 382 undeveloped net locations.

Undeveloped Net Utica Locations - We assume these locations have 8,000 foot laterals and 750 foot spacing between wells which yields approximately 138 acre spacing. In the Utica, we apply a 10% risking factor to our net acreage to account for inefficient unitization. As of December 31, 2014, we had 55,000 net acres prospective for the Utica in Ohio which results in 356 undeveloped net locations.

“Horizontal drilling.” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

“Mcf.” One thousand cubic feet of natural gas.

“Mcf.” One thousand cubic feet of natural gas equivalent, determined by using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate of natural gas liquids.

“MMcf.” One million cubic feet of natural gas.

“MMcfe.” One million cubic feet of natural gas equivalent, determined by using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate of natural gas liquids.

“MMBtu.” One million Btu.

“NGLs.” Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

“NYMEX.” The New York Mercantile Exchange.

“Net acres.” The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

“Productive well.” A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

“Prospect.” A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

“Proved developed reserves.” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“Proved reserves.” The estimated quantities of oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

“Proved undeveloped reserves (“PUD”).” Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

“PV-10.” When used with respect to natural gas and oil reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.

“Recompletion.” The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

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

“Spacing.” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

“Standardized measure.” Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

“Total depth.” The planned end of a well, measured by the length of pipe required to reach the bottom.

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

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

“Wellbore.” The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

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