Atlas Resource Partners, L.P.
Form 10-K
March 07, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR

o 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: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction or incorporation or organization)	45-3591625 (I.R.S. Employer Identification No.)
Park Place Corporate Center One 1000 Commerce Drive, Suite 400	15275

Pittsburgh, PA
(Address of principal executive offices) Zip code
Registrant's telephone number, including area code: 800-251-0171

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

Title of each class	Name of each exchange on which registered
Common Units representing Limited Partnership Interests	New York Stock Exchange
8.625% Class D Cumulative Redeemable Perpetual Preferred Units	New York Stock Exchange
10.75% Class E Cumulative Redeemable Perpetual Preferred Units	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 o No x

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

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

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

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

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

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of the voting and non-voting equity securities held by non-affiliates of the registrant, based on the closing price of the registrant's common units on the last business day of the registrant's most recently completed second quarter, June 30, 2015, was approximately $457.9 million.

The number of outstanding common limited partner units of the registrant on February 29, 2016 was 102,421,097.

DOCUMENTS INCORPORATED BY REFERENCE: None

ATLAS RESOURCE PARTNERS, L.P.

INDEX TO ANNUAL REPORT

ON FORM 10-K

TABLE OF CONTENTS

GLOSSARY OF TERMS

Unless the context otherwise requires, references below to “Atlas Resource Partners, L.P.,” “Atlas Resource Partners,” “the Partnership,” “we,” “us,” “our” and “our company”, when used in a historical context, refer to the subsidiaries and operations that Atlas Energy, L.P. contributed to Atlas Resource Partners in connection with the separation and distribution completed in March 2012, and, when used in the present tense or prospectively, refer to Atlas Resource Partners, L.P. and its combined subsidiaries. References below to “Atlas Energy” or “Atlas Energy, L.P.” refers to Atlas Energy, L.P. and its consolidated subsidiaries prior to the February 2015 merger of Atlas Energy discussed herein, unless the context otherwise requires.

Bbl. One barrel of crude oil, condensate or other liquid hydrocarbons equal to 42 United States gallons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of gas to one Bbl oil, condensate or natural gas liquids.

Bpd. Barrels per day.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

Dth. One dekatherm, equivalent to one million British thermal units.

Dth/d. Dekatherms per day.

Dry hole or well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

EBITDA. Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is considered to be a non-GAAP measurement.

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

FASB. Financial Accounting Standards Board.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

Fractionation. The process used to separate a natural gas liquid stream into its individual components.

GAAP. Generally Accepted Accounting Principles in the United States of America.

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

MBbl. One thousand barrels of crude oil, condensate or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas; the standard unit for measuring volumes of natural gas.

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

Mcfd. One thousand cubic feet per day.

Mcfed. One Mcfe per day.

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

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

MMcfed. One MMcfe per day.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

Natural Gas Liquids or NGLs —A mixture of light hydrocarbons that exist in the gaseous phase at reservoir conditions but are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus (the main constituent of condensates).

NYMEX. The New York Mercantile Exchange.

NYSE. The New York Stock Exchange.

Oil. Crude oil and condensate.

Productive well. A producing well or well that is found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil and gas well.

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

Proved Reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(a) The area identified by drilling and limited by fluid contacts, if any, and

(b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(b) The project has been approved for development by all necessary parties and entities, including governmental entities.
(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved Undeveloped Reserves or PUDs. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

PV-10. Present value of future net revenues. See the definition of “standardized measure.”

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reserves. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

SEC. Securities Exchange Commission.

Standardized Measure. Standardized measure, or standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities, is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses, debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

Successful well. A well capable of producing oil and/or gas in commercial quantities.

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 oil and gas regardless of whether such acreage contains proved reserves.

Unproved Reserves. Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.

Working Interest. An operating interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and the responsibility to pay royalties and a share of the costs of drilling and production operations under the applicable fiscal terms. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100.00% working interest in a lease burdened only by a landowner’s royalty of 12.50% would be required to pay 100.00% of the costs of a well but would be entitled to retain 87.50% of the production.

FORWARD-LOOKING STATEMENTS

The matters discussed within this report include forward-looking statements. These statements may be identified by the use of forward-looking terminology such as “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “intend,” “m “might,” “plan,” “potential,” “predict,” “should,” or “will,” or the negative thereof or other variations thereon or comparable terminology. In particular, statements about our expectations, beliefs, plans, objectives, assumptions or future events or performance contained in this report are forward-looking statements. We have based these forward-looking statements on our current expectations, assumptions, estimates and projections. While we believe these expectations, assumptions, estimates and projections are reasonable, such forward-looking statements are only predictions and involve known and unknown risks and uncertainties, many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. Some of the key factors that could cause actual results to differ from our expectations include:

- the demand for natural gas, oil, NGLs and condensate;
- the price volatility of natural gas, oil, NGLs and condensate;
- changes in the differential between benchmark prices for oil and natural gas and wellhead prices that we receive;
- changes in the market price of our units;
- future financial and operating results;
- our ability to meet our liquidity needs, including as a result of borrowing base redeterminations;
- restrictive covenants in the debt documents governing our indebtedness that may adversely affect operational flexibility;
- actions that we may take in connection with our liquidity needs, including the ability to service our debt, and ability to satisfy covenants in our debt documents;
- economic conditions and instability in the financial markets;
- effects of debt payment obligations on our distributable cash;
- resource potential;
- our ability to meet or exceed the continued listing standards of the New York Stock Exchange;
- effects of partial depletion or drainage by earlier offset drilling on our acreage;
- success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves;
- the accuracy of estimated natural gas and oil reserves;
- the financial and accounting impact of hedging transactions;
- the ability to fulfill our substantial capital investment needs;
- expectations with regard to acquisition activity, or difficulties encountered in connection with acquisitions, dispositions or similar transactions;

- the limited payment of distributions, or failure to declare a distribution, on outstanding common units or other equity securities;

6

- any issuance of additional common units or other equity securities, and any resulting dilution or decline in the market price of any such securities;
- potential changes in tax laws which may impair the ability to obtain capital funds through investment partnerships;
- the ability to obtain adequate water to conduct drilling and production operations, and to dispose of the water used in and generated by these operations at a reasonable cost and within applicable environmental rules;
- the effects of unexpected operational events and drilling conditions, and other risks associated with drilling operations;
- impact fees and severance taxes;
- changes and potential changes in the regulatory and enforcement environment in the areas in which we conduct business;
- the effects of intense competition in the natural gas and oil industry;
- general market, labor and economic conditions and uncertainties;
- the ability to retain certain key customers;
- dependence on the gathering and transportation facilities of third parties;
- the availability of drilling rigs, equipment and crews;
- potential incurrence of significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment;
- access to sufficient amounts of carbon dioxide for tertiary recovery operations;
- uncertainties with respect to the success of drilling wells at identified drilling locations;
- acquisitions may potentially prove to be worth less than we paid, or provide less than anticipated proved reserves;
- ability to identify all risks associated with the acquisition of oil and natural gas properties, or existing wells, and the sufficiency of indemnifications we receive from sellers to protect us from such risks;
- expirations of undeveloped leasehold acreage;
- uncertainty regarding leasing operating expenses, general and administrative expenses and funding and development costs;
- exposure to financial and other liabilities of the managing general partners of the investment partnerships;
- the ability to comply with, and the potential costs of compliance with, new and existing federal, state, local and other laws and regulations applicable to our business and operations;
- restrictions on hydraulic fracturing;
- exposure to new and existing litigation;
- development of alternative energy resources; and
- the effects of a cyber event or terrorist attack.

Other factors that could cause actual results to differ from those implied by the forward-looking statements in this report are more fully described under “Item 1A: Risk Factors” in this report. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

PART I

ITEM 1: BUSINESS

Overview

We are a publicly-traded master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas, crude oil and natural gas liquids (“NGL”), with operations in basins across the United States. We are a leading sponsor and manager of tax-advantaged investment partnerships (“Drilling Partnerships”), in which we co-invest, to finance a portion of our natural gas, crude oil and natural gas liquids production activities.

We believe we have established a strong track record of growing our reserves, production and cash flows through a balanced mix of natural gas, oil and natural gas liquids exploitation and development, sponsorship of our Drilling Partnerships, and the acquisition of oil and gas properties. Our primary business objective is to generate growing yet stable cash flows through the development and acquisition of mature, long-lived natural gas, oil and natural gas liquids properties. As of December 31, 2015, our estimated proved reserves were 921 Bcfe, including the reserves net to our equity interest in our Drilling Partnerships. Of our estimated proved reserves, approximately 82% were proved developed and approximately 66% were natural gas. For the year ended December 31, 2015, our average daily net production was approximately 266.4 MMcfe. Through December 31, 2015, we own production positions in the following areas:

- the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas where we have ownership interests in approximately 736 proved developed wells and 10 proved undeveloped locations totaling 139 Bcfe of total proved reserves with average daily production of 60.6 MMcfe for the year ended December 31, 2015;
- the coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Central Appalachian Basin in southern West Virginia and southwestern Virginia, and Arkoma where we have ownership interests in approximately 3,646 proved developed wells and 18 proved undeveloped locations totaling 378 Bcfe of total proved reserves with average daily production of 129.5 MMcfe for the year ended December 31, 2015;
- the Appalachia Basin, including the Marcellus Shale and the Utica Shale where we have ownership interests in approximately 8,620 wells, including approximately 271 wells in the Marcellus Shale, and 90 Bcfe of total proved reserves with average daily production of 34.1 MMcfe for the year ended December 31, 2015;
- the Eagle Ford Shale in southern Texas where we have ownership interests in approximately 27 proved developed wells and 72 proved undeveloped locations in the Eagle Ford Shale totaling 115 Bcfe of total proved reserves with average daily production of 9.4 MMcfe for the year ended December 31, 2015;
- the Rangely field in northwest Colorado where we have non-operated ownership interests in approximately 400 wells in the Rangely field and 170 Bcfe of total proved reserves with average daily production of 15.8 MMcfe for the year ended December 31, 2015;
- the Mississippi Lime and Hunton plays in northwestern Oklahoma where we have ownership interests in approximately 108 proved developed wells and 18 Bcfe of total proved reserves with average daily production of 12.3 MMcfe for the year ended December 31, 2015; and
- other operating areas, including the Chattanooga Shale in northeastern Tennessee, the New Albany Shale in southwestern Indiana and the Niobrara Shale in northeastern Colorado in which we have an aggregate 11 Bcfe of total proved reserves with average daily production of 4.8 MMcfe for the year ended December 31, 2015.

We seek to create substantial value by executing our strategy of acquiring properties with stable, long-life production, relatively predictable decline curves and lower risk development opportunities. Over the three years ended December 31, 2015, we have acquired significant net proved reserves and production through the following transactions:

·

EP Energy Acquisition. On July 31, 2013, we completed the acquisition of certain assets from EP Energy E&P Company, L.P ("EP Energy") for approximately $709.6 million in net cash (the "EP Energy Acquisition"). The coal-bed methane producing natural gas assets included approximately 3,000 producing wells generating net production of approximately 119 MMcfed on the date of acquisition from EP Energy on approximately 700,000 net acres in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming.

- GeoMet Acquisition—On May 12, 2014, we completed the acquisition of certain assets from GeoMet, Inc. for approximately $97.9 million in cash, net of purchase price adjustments, with an effective date of January 1, 2014 (the "GeoMet Acquisition"). The coal-bed methane producing natural gas assets include approximately 70 Bcfe of proved reserves with over 400 active wells generating 22 MMcfed on the date of acquisition in the Central Appalachian Basin in West Virginia and Virginia.

- Rangely Acquisition—On June 30, 2014, we completed the acquisition of a 25% non-operated net working interest in oil and NGL producing assets, representing approximately 47 Mmboe reserves for $408.9 million in cash with an effective date of April 1, 2014 (the "Rangely Acquisition"). The assets are located in the Rangely field in northwest Colorado. The acquired assets are expected to provide us with a stable, high margin cash flow stream with a low-decline profile (average 3-4% annual decline rate over the past 15 years). The asset position is a tertiary oil recovery project using CO2 flood activity, and the production mix is 90% oil, with the remainder coming from NGLs. Chevron Corporation (NYSE: CVX; "Chevron") will continue as operator of the assets.
- Eagle Ford Acquisition—On November 5, 2014, we and our affiliate, Atlas Growth Partners, L.P. ("AGP"), completed the acquisition of interests in oil and natural gas assets in the Eagle Ford Shale in South Central Atascosa County, Texas, including 4,000 operated gross acres and net reserves of 12 Mmboe as of July 1, 2014 (the "Eagle Ford Acquisition"). The purchase price was $342.0 million, our initial share of the aggregate purchase price was $206.5 million and AGP's share was $135.5 million. The Eagle Ford Acquisition had an effective date of July 1, 2014. On July 8, 2015, AGP sold to us, for a purchase price of $1.4 million, AGP's interest in a portion of the acreage it acquired in the Eagle Ford Acquisition. On September 21, 2015, we and AGP, in accordance with the terms of the Eagle Ford shared acquisition and operating agreement, agreed that we would fund AGP's remaining two deferred purchase price installments of $16.2 million and $20.1 million to be paid on September 30, 2015 and December 31, 2015, respectively. In conjunction with this agreement, AGP assigned us a portion of its non-operating Eagle Ford assets that had an allocated value (as such value was agreed upon by the sellers and the buyers in connection with the Eagle Ford Acquisition) equal to both installments to be paid by us. The transaction was approved by our and AGP's respective conflicts committees. As a result, our final share of the aggregate purchase price was $242.8 million and AGP's share was $99.2 million.
- Arkoma Acquisition—On June 5, 2015, we completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition").

On February 27, 2015, our general partner, Atlas Energy Group, LLC ("Atlas Energy Group"; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. ("Atlas Energy"), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as "ATLS"). Atlas Energy Group manages our operations and activities through its ownership of our general partner interest. Concurrent with Atlas Energy Group's unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. ("Targa"; NYSE: TRGP) (the "Atlas Merger") and ceased trading. At December 31, 2015, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

Our operations include three reportable operating segments: gas and oil production, well construction and completion and other partnership management (see "Item 8: Financial Statements and Supplementary Data – Note 15").

Competitive Strengths

We believe we are well-positioned to successfully execute our business strategy because of the following competitive strengths:

We have a high quality, long-lived reserve base. Our natural gas and oil properties are located principally in the Barnett and Eagle Ford shales, the Marble Falls play, the Mississippi Lime, the Raton, Black Warrior and Appalachian basins and the Rangely field, and are characterized by long-lived reserves, generally favorable pricing for our production and readily available transportation.

We have significant experience in making accretive acquisitions. Our management team has extensive experience in consummating accretive acquisitions. We believe we will be able to generate acquisition opportunities of both producing and non-producing properties through our management's extensive industry relationships. We intend to use these relationships and experience to find, evaluate and execute on acquisition opportunities.

We have significant engineering, geologic and management experience. Our technical team of geologists and engineers has extensive industry experience. We believe that we have been one of the most active drillers in our core operating areas and, as a result, that we have accumulated extensive geological and geographical knowledge about these areas. We have also added geologists and engineers to our technical staff who have significant experience in other productive basins within the continental United States, which enables us to evaluate and expand our core operating areas.

We are one of the leading sponsors of tax-advantaged Drilling Partnerships. We and our predecessor have sponsored limited and general partnerships to raise funds from investors to finance our development drilling activities since 1968, and we believe that we are one of the leading sponsors of such Drilling Partnerships in the country. We believe that our lengthy association with many of the broker-dealers that act as placement agents for our Drilling Partnerships provide us with a competitive advantage over entities with similar operations. We also believe that our sponsorship of Drilling Partnerships has allowed us to generate attractive returns on drilling, operating and production activities.

Fee-based revenues from our Drilling Partnerships and our substantially hedged production provide protection from commodity price volatility. Our Drilling Partnerships provide us with stable, fee-based revenues which diminish the influence of commodity price fluctuations on our cash flows. Because our Drilling Partnerships reimburse us on a cost-plus basis for drilling capital expenses, we are partially protected against increases in drilling costs. Our fees for managing our Drilling Partnerships accounted for approximately 15% of our segment margin for the year ended December 31, 2015. Additionally, our natural gas, crude oil and NGL production was hedged approximately 75% on an equivalent basis for the year ended December 31, 2015. As of December 31, 2015, we had approximately 160.2 Bcf, 4.3 Mmbbl and 0.1 Mmbbl of hedge positions, respectively, on our natural gas, crude oil and NGL production for 2016 through 2019.

Our partnership management business can improve the economic rates of return associated with our natural gas and oil production activities. A well drilled, net to our equity interest, in our partnership management business will provide us with an enhanced rate of return. For each well drilled in a partnership, we receive an upfront fee on the investors' well construction and completion costs and a fixed administration and oversight fee, which enhances our overall rate of return. We also receive monthly per well fees from the partnership for the life of each individual well, which also increases our rate of return.

Business Strategy

The key elements of our business strategy are:

Continue to manage our capital structure. We continually monitor the capital markets, our capital structure and our leverage ratios and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency.

Continue to manage our exposure to commodity price risk. To limit our exposure to changing commodity prices and enhance and stabilize our cash flow, we use financial hedges for a portion of our natural gas and oil production. We principally use fixed price swaps and collars as the mechanism for the financial hedging of our commodity prices.

Continue to maintain control of operations and costs. We believe it is important to be the operator of wells in which we or our Drilling Partnerships have an interest because we believe it will allow us to achieve operating efficiencies and control costs. As operator, we are better positioned to control the timing and plans for future enhancement and exploitation efforts, costs of enhancing, drilling, completing and producing the well, and marketing negotiations for our natural gas, oil, and NGL production to maximize both volumes and wellhead price. We were the operator of the vast majority of the properties in which we or our Drilling Partnerships had a working interest at December 31, 2015.

Expand our natural gas and oil production. We generate a significant portion of our revenue and net cash flow from natural gas and oil production. We believe our program of sponsoring Drilling Partnerships to exploit our acreage opportunities provides us with enhanced economic returns. For the five year period ended December 31, 2015, we raised over $0.6 billion from outside investors through our Drilling Partnerships. We intend to continue to develop our inventory of proved undeveloped locations through both sponsorship of Drilling Partnerships and direct well drilling to add value through reserve and production growth.

Expand our fee-based revenue through our sponsorship of Drilling Partnerships. We generate substantial revenue and cash flow from fees paid by the Drilling Partnerships to us for acting as the managing general partner. As we continue to sponsor Drilling Partnerships, we expect that our fee revenues from our drilling and operating agreements with our Drilling Partnerships will increase and will add stability to our revenue and cash flows.

Expand operations through strategic acquisitions. We continually evaluate opportunities to expand our operations through acquisitions of developed and undeveloped properties or companies that can increase our cash available for distribution. We will continue to seek strategic opportunities in our current areas of operation, as well as other regions of the United States.

Subsequent Events

Senior Note Repurchases. In January and February 2016, we executed transactions to repurchase portions of our senior unsecured notes. Through the end of February 2016, we have repurchased approximately $20.3 million of our 7.75% Senior Notes due 2021 and approximately $12.1 million of our 9.25% Senior Notes for approximately $5.5 million. As a result of these transactions, we will recognize approximately $25.9 million as gain on early extinguishment of debt in the first quarter of 2016.

Cash Distributions. On January 28, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of December 31, 2015. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of common units and Class C preferred limited units, respectively, was paid on February 12, 2016 to unitholders of record at the close of business on February 8, 2016.

On February 24, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of January 31, 2016. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of common units and Class C preferred limited units, respectively, will be paid on March 16, 2016 to unitholders of record at the close of business on March 9, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.5390625 per Class D Preferred Unit, or $2.2 million, for the period from October 15, 2015 through January 14, 2016 to Class D Preferred Unitholders of record as of January 4, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.671875 per Class E Preferred Unit, or $0.2 million, for the period from October 15, 2015 through January 14, 2016 to Class E Preferred Unitholders of record as of January 4, 2016.

NYSE Compliance. On January 12, 2016, we were notified by the NYSE that we were not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of the common units had been less than $1.00 for 30 consecutive trading days. We are working to remedy this situation in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE.

Recent Developments

Credit Facility Amendment. On November 23, 2015, we entered into an Eighth Amendment to the Second Amended and Restated Credit Agreement (the "Amendment") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amendment amends the Second Amended and Restated Credit Agreement dated July 31, 2013 (as amended from time to time, the "Credit Agreement"). Among other things, the Eighth Amendment:

- reduced the borrowing base under the Credit Agreement from $750.0 million to $700.0 million;
- increased the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- permits the incurrence of third lien debt subject to the satisfaction of certain conditions, including pro forma financial covenant compliance;
- upon the issuance of any third lien debt, reduces the borrowing base by 25% of the stated amount of such third lien debt (other than third lien debt that is used to refinance senior notes, second lien debt and other third lien debt);
- suspends compliance with a maximum ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) until the four fiscal quarter period ending March 31, 2017 and revised the

maximum ratio of Total Funded Debt to EBITDA to be 5.75 to 1.00 for the four quarter periods ending March 31, 2017 and June 30, 2017, 5.50 to 1.00 for the four quarter periods ending September 30, 2017 and December 31, 2017, 5.25 to 1.00 for the four quarter period ending March 31, 2018, and 5.00 to 1.00 for each four fiscal quarter period ending thereafter;

- replaced the requirement to maintain compliance with a maximum ratio of Senior Secured Total Funded Debt to EBITDA with a requirement to be in compliance with a maximum ratio of First Lien Debt (as defined in the Credit Agreement) to EBITDA of 2.75 to1.00; and
- reset the distribution to $0.15 per common unit and permits increases to the distribution per common unit if (a) the ratio of Total Funded Debt (as of such date) to EBITDA for the most recent four fiscal quarters is equal to or less than 5.00 to1.00 and (b) the borrowing base utilization is less than or equal to 85%, on a pro forma basis after giving effect to the distribution payments.

A Seventh Amendment to the Credit Agreement was entered into on July 24, 2015. Among other things, the Seventh Amendment redefined EBITDA.

A Sixth Amendment to the Credit Agreement was entered into on February 23, 2015. Among other things, the Sixth Amendment:

- reduced the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;
- permitted the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;
- rescheduled the May 1, 2015 borrowing base redetermination for July 1, 2015;
- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and
- revised the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

Funding of AGP's Eagle Ford Deferred Purchase Price. In connection with the Eagle Ford Acquisition, we guaranteed the timely payment of the deferred portion of the purchase price that was to be paid by AGP. Pursuant to the agreement between us and AGP, we had the right to receive some or all of the assets acquired by AGP in the event of its failure to contribute its portion of any deferred payments. In connection with the second installment payments, we and AGP amended the purchase and sale agreement to alter the timing and amount of the quarterly installment payments beginning on March 31, 2015 and ending December 31, 2015 (see "Overview – Eagle Ford Acquisition"). On September 21, 2015, we and AGP, in accordance with the terms of the Eagle Ford shared acquisition and operating agreement, agreed that we would fund AGP's remaining two deferred purchase price installments.

Arkoma Acquisition. On June 5, 2015, we completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). We funded the purchase price through the issuance of 6,500,000 common limited partner units. The Arkoma Acquisition had an effective date of January 1, 2015, however, as the acquisition constituted a transaction between entities under common control, we retrospectively adjusted our consolidated financial statements for dates prior to the date of acquisition to reflect our results on a consolidated basis with the results of the Arkoma assets as of or at the beginning of the respective period.

Issuance of Common Units. In May 2015, in connection with the Arkoma Acquisition, we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.5 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our revolving credit facility.

Issuance of Preferred Units. In April 2015, we issued 255,000 of our 10.75% Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units") at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. We pay distributions on the Class E Preferred Units at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

Second Lien Term Loan Facility. On February 23, 2015, we entered into a Second Lien Credit Agreement (the "Second Lien Credit Agreement") with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"). The Term Loan Facility matures on February 23, 2020.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the last day of the applicable interest period (or, with respect to interest periods of more than three-months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period) for Eurodollar loans and quarterly for ABR loans.

Geographic and Geologic Overview

Through December 31, 2015, the majority of our production positions were in the following areas:

Barnett Shale/Marble Falls. The Barnett Shale and Marble Falls play are located east of the Bend Arch and west of the Quachita Thrust in the Fort Worth Basin of northern Texas. The Barnett Shale is Mississippian-age shale formation located at depths between 5,000 and 8,000 feet and ranges in thickness from 100 and 600 feet. The Marble Falls play is Pennsylvanian-age formation located above the Barnett Shale and beneath the Atoka at depths of approximately 5,500 feet and ranges in thickness from 50 and 500 feet. As of December 31, 2015, we had an interest in approximately 746 Barnett Shale and Marble Falls wells. As of December 31, 2015, we had more than 88,077 net acres prospective for the Barnett Shale/Marble Falls play.

Appalachian Basin. The Appalachian Basin includes all or parts of: Alabama, Georgia, Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. It is the most mature natural gas, crude oil and NGL producing region in the United States, having established the first oil production in 1860. Our development and production activities in the Appalachia Basin principally include the Marcellus Shale, Utica-Point Pleasant Shale, Clinton Sand and other conventional formations primarily in Pennsylvania and Ohio.

The Marcellus Shale is a black, organic rich shale formation located at depths between 4,000 and 8,500 feet and ranges in thickness from 50 to 250 feet. As of December 31, 2015, we had an interest in approximately 271 Marcellus Shale wells, consisting of 228 vertical wells and 43 horizontal wells. As of December 31, 2015, we had an interest in eight horizontal Marcellus Shale wells in Northeastern Pennsylvania, all of which were developed through Drilling Partnerships. Also as of December 31, 2015, approximately 1,456 prospective Marcellus Shale acres remained undeveloped in Lycoming County, Pennsylvania. Our drilling activity in certain portions of the Appalachian Basin located in southwestern Pennsylvania, West Virginia and New York were limited until February 17, 2014 by the terms of the non-competition agreements between certain of ATLS's officers and directors and Chevron Corporation.

The Utica-Point Pleasant Shale is an Ordovician-age shale which covers a large portion of Ohio, Pennsylvania, New York and West Virginia and lies several thousand feet below the Devonian-age Marcellus. The Utica-Point Pleasant is an organic rich system comprised of two related shales. The richest concentration of organic material is present within the Point Pleasant member of the Lower Utica formation; therefore, the primary objective section of this shale play. From central Ohio, the Utica-Point Pleasant play has gentle basin center dip towards its deepest point in central Pennsylvania. In general, as the present day depth increases from West to East, so does the progression of hydrocarbon maturity-along the following, ordered hydrocarbon phase windows: Immature-Oil-Condensate-Rich Gas-Dry Gas Windows. As of December 31, 2015, we had an interest in approximately 2,373 wells in Ohio including 12 horizontal Utica-Point Pleasant wells. As of December 31, 2015, we had approximately 1,394 net undeveloped acres prospective for the Utica Shale in Trumbull and Stark counties in Ohio.

Coal-Bed Methane. Our coal-bed methane developments are diversified across four well-known coal-bed methane producing areas: the Raton, Black Warrior, Arkoma and Central Appalachian basins. As of December 31, 2015, we had more than 455,630 net undeveloped acres prospective for coal-bed methane. Also as of December 31, 2015, we operated 2,831 wells and had an interest in another 833 wells, all of which produce gas generated from coal.

The Raton asset straddles the New Mexico-Colorado border, along the eastern edge of the Sangre de Cristo Mountains. The production derives from two coal-bearing intervals, the Raton (Tertiary-Upper Cretaceous Age) and Vermajo (Cretaceous Age) formations. The combined net coal thickness ranges between 18 and 65 feet, with depths between 750 and 2,200 feet. As of December 31, 2015, we operated 973 wells at the Raton asset.

The Black Warrior coal-bed methane asset is located in central Alabama and geologically related with the frontal thrusts associated with the Appalachian Mountains. The three Pennsylvanian-age coal intervals (Pratt, Mary Lee and Black Creek, listed in increasing stratigraphic depth and age) possess combined net coal thicknesses ranging from 16 to 24 feet, at depths of 500 to 2,400 feet. As of December 31, 2015, we operated 882 wells and had an interest in an additional 695 wells at the Black Warrior asset.

The Arkoma coal-bed methane asset is located in eastern Oklahoma and the Arkoma basin formed by the Ouachita Mountain uplift to the southeast. The main producing coal is the Hartshorne Coal seam which is of middle Pennsylvanian Age. The net coal thickness ranges from 5 to 10 feet, at depths of 14 to 4,900 feet. As of December 31, 2015, we operated 564 wells and had an interest in an additional 66 wells at the Arkoma asset.

The Central Appalachian coal-bed methane asset is located in Virginia and West Virginia. The Central Appalachian Basin is a mountainous region where coal mining is prevalent. We operate vertical wells in the Pond Creek and Lasher fields located in southern West Virginia and southwestern Virginia and pinnate horizontal wells in southern and northern West Virginia. As of December 31, 2015, we operated 412 wells and had an interest in an additional 72 wells in Virginia and West Virginia.

Rangely. The Rangely Oil Field, located in northwestern Colorado, is one of the oldest and largest oil fields in the Rocky Mountain region. We have an approximate 25% non-operating net working interest in the assets and Chevron Corporation is the current owner/operator of the Rangely Weber Sand Unit. The Weber Formation is Permian to Pennsylvanian in age (245-315 million years ago), and typically consists of fine-grained, cross-bedded calcareous sandstones. Average thickness of the unit is 1,200 feet, although the gross reservoir thickness averages 530 feet, and the net production interval within the formation varies from approximately 150 to 250 feet.

Eagle Ford. The Eagle Ford Shale is an Upper Cretaceous-age formation that is prospective for horizontal drilling in approximately 26 counties across South Texas. Target vertical depths range from 4,000 to some 11,000+ feet with thickness from 40 to over 400 feet. The Eagle Ford formation is considered to be the primary source rock for many conventional oil and gas fields including the prolific East Texas Oil Field, one of the largest oil fields in the contiguous United States. As of December 31, 2015, we had 27 producing wells and 72 undeveloped locations in the Eagle Ford Shale.

Mississippi Lime/Hunton. The Mississippi Lime and Hunton formations are located in the Anadarko Shelf in northern Oklahoma. The Mississippi Lime formation is an expansive carbonate hydrocarbon system and is located at depths between 4,000 and 7,000 feet between the Pennsylvanian-aged Morrow formation and the Devonian-age world-class source rock Woodford Shale formation. The Mississippi Lime formation can reach 600 feet in gross thickness, with a targeted porosity zone between 50 and 100 feet thickness. The Hunton formation is a limestone formation located at a depth of approximately 7,500 feet, and ranges in thickness from 150 and 300 feet. As of December 31, 2015, we had an interest in approximately 78 Mississippi Lime wells and 30 Hunton wells.

Gas and Oil Production

Production Volumes

Currently, our natural gas, crude oil and NGL production operations are focused in various plays throughout the United States, and include direct interest wells and ownership interests in wells drilled through our Drilling Partnerships. When we drill new wells through our partnership management business we receive an interest in each Drilling Partnership proportionate to the value of our co-investment in it and the value of the acreage we contribute to it, typically 30% of the overall capitalization of a particular partnership. The following table presents our total net natural gas, oil and natural gas liquids production volumes and production per day for the three years ended December 31, 2015, 2014, and 2013:

	Years Ended December 31,		
	2015	2014	2013
Production per day:(1)(2)			
Natural gas (Mcfd)	216,613	238,054	163,971
Oil (Bpd)	5,139	3,436	1,329
Natural gas liquids (Bpd)	3,155	3,802	3,473
Total (Mcfed)	266,374	281,486	192,786

(1) “Mcfd” represents thousand cubic feet per day; “Mcfed” represents thousand cubic feet equivalents per day; and “Bpd” represents barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.
(2) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of

production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such partnership and based on each partnership's proportionate net revenue interest in these wells.

Production Revenues, Prices and Costs

Our production revenues and estimated gas, oil and natural gas liquids reserves are substantially dependent on prevailing market prices for natural gas and oil prices. The following table presents our production revenues and average sales prices for our natural gas, oil and natural gas liquids production for the years ended December 31, 2015, 2014, and 2013, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Years Ended December 31,		
	2015	2014	2013
Production revenues (in thousands):			
Natural gas revenue	$217,236	$318,920	$193,050
Oil revenue	122,273	110,070	44,160
Natural gas liquids revenue	17,490	41,061	36,394
Total revenues	$356,999	$470,051	$273,604
Average sales price:(1)			
Natural gas (per Mcf):			
Total realized price, after hedge(2)(3)	$3.41	$3.76	$3.48
Total realized price, before hedge(2)	$2.23	$3.93	$3.25
Oil (per Bbl):			
Total realized price, after hedge(3)	$84.30	$87.76	$91.01
Total realized price, before hedge	$44.19	$82.22	$95.88
NGLs (per Bbl):			
Total realized price, after hedge(3)	$22.40	$29.59	$28.71
Total realized price, before hedge	$12.77	$29.39	$29.43
Production costs (per Mcfe):(1)			
Lease operating expenses(4)	$1.34	$1.27	$1.08
Production taxes	0.19	0.27	0.18
Transportation and compression	0.24	0.25	0.25
Total	$1.76	$1.80	$1.50

(1) "Mcf" represents thousand cubic feet; "Mcfe" represents thousand cubic feet equivalents; and "Bbl" represents barrels.
(2) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effect of this subordination, the average realized gas sales prices were $3.36 per Mcf ($2.19 per Mcf before the effects of financial hedging), $3.67 per Mcf ($3.84 per Mcf before the effects of financial hedging), and $3.23 per Mcf ($3.00 per Mcf before the effects of financial hedging) for the years ended December 31, 2015, 2014 and 2013, respectively.
(3) Includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015, consisting of $48.6 million associated with natural gas derivative contracts, $35.8 million associated with crude oil derivative contracts, and $8.3 million associated with natural gas liquids derivative contracts for the year ended December 31, 2015 (see "Item 8. Financial Statements – Note 8").

(4) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effects of these costs, total lease operating expenses per Mcfe were $1.32 per Mcfe ($1.74 per Mcfe for total production costs), $1.25 per Mcfe ($1.77 per Mcfe for total production costs), and $1.00 per Mcfe ($1.42 per Mcfe for total production costs) for the years ended December 31, 2015, 2014 and 2013, respectively.

Partnership Management Business

Certain energy activities are conducted by us through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we will recognize a current liability titled “Liabilities Associated with Drilling Contracts” on our consolidated balance sheets. After the Drilling Partnership well is completed and turned in line, we are entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees we are entitled to receive for services provided, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%.

Over the last five years, we raised over $645.1 million from outside investors for participation in our Drilling Partnerships. Net proceeds from these partnerships are used to fund the investors' share of drilling and completion costs under our drilling contracts with the partnerships.

Our fund raising activities for sponsored Drilling Partnerships during the last five years are summarized in the following table (amounts in millions):

	Drilling Program Capital		
	Investor contributions	Our contributions	Total capital
2015	$59.3	$ 17.6	$76.9
2014	166.8	71.0	237.8
2013	150.0	92.3	242.3
2012	127.1	54.4	181.5
2011	141.9	28.3	170.2
Total	$645.1	$ 263.6	$908.7

As managing general partner of our Drilling Partnerships, we recognize our Drilling Partnership management fees in the following manner:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, we receive a 15% mark-up on those costs incurred to drill and complete the wells included within the partnership. Such fees are earned, in accordance with the partnership agreement, and recognized as the services are performed, typically between 60 and 270 days, using the percentage of completion method;
- Administration and oversight. For each well drilled by a Drilling Partnership, we receive a fixed fee between $100,000 and $500,000, depending on the type of well drilled, which is earned in accordance with the partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of $75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed; and
- Well services. Each Drilling Partnership pays us a monthly per well operating fee, currently $1,000 to $2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed;

Gathering and processing revenue includes gathering fees we charge to the Drilling Partnership wells for our processing plants in the New Albany and the Chattanooga Shales. Generally, we charge a gathering fee to the Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from Drilling Partnerships by approximately 3%.

Our Drilling Partnerships provide tax advantages to our investors because an investor's share of the partnership's intangible drilling cost deduction may be used to offset ordinary income. Intangible drilling costs include items that do not have salvage value, such as labor, fuel, repairs, supplies and hauling. Generally, for our Drilling Partnerships, approximately 80% to 94% of the subscription proceeds received have been used to pay 100% of the partnership's intangible drilling costs. For example, an investment of $10,000 generally permits the investor to deduct from taxable ordinary income approximately $8,000 to $9,400 in the year in which the investor invests.

16

While our historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

Drilling Activity

The number of wells we drill will vary depending on, among other things, the amount of money we raise through our Drilling Partnerships, the cost of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table sets forth information with respect to the number of wells we drilled, both gross and for our interest, during the periods indicated. There were no exploratory wells drilled during the years ended December 31, 2015, 2014, and 2013.

	Years Ended December 31,		
	2015(3)	2014(3)	2013(3)
Gross wells drilled	28	129	103
Net wells drilled(1)	17	67	66
Gross wells turned in line(2)	36	119	117
Net wells turned in line(2)	15	64	80

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage interest in our Drilling Partnerships.
(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.
(3) There were no exploratory wells drilled during the years ended December 31, 2015, 2014 and 2013; there were no gross or net dry wells within our operating areas during the year ended December 31, 2015, 2014 and 2013.

We do not operate any of the rigs or related equipment used in our drilling operations, relying instead on specialized subcontractors or joint venture partners for all drilling and completion work. This enables us to streamline our operations and conserve capital for investments in new wells, infrastructure and property acquisitions, while generally retaining control over all geological, drilling, engineering and operating decisions. We perform regular inspection, testing and monitoring functions on each of our Drilling Partnerships and our operated wells.

As of December 31, 2015, we had the following ongoing drilling activities:

	Gross			Net		
	Spud	Total Depth	Completed	Spud	Total Depth	Completed
Eagle Ford - Horizontal	2	8	—	1	1	—

Natural Gas and Oil Leases

The typical oil and gas lease agreement provides for the payment of a percentage of the proceeds, known as a royalty, to the mineral owner(s) for all natural gas, oil and other hydrocarbons produced from any well(s) drilled on the leased premises. In the Appalachian Basin and much of the United States, this amount, historically, has ranged between 1/8th (12.5%) and 1/6th (16.66%) of the hydrocarbons produced, resulting in a net revenue interest to us of between 87.5% and 83.33%. With the discovery of the Marcellus and Utica Shales in the Appalachian Basin in the last few years, and the resultant competition for undeveloped acreage, it has become very common for landowners to demand royalty rates up to 20% or higher, resulting in a net revenue interest of 80% or less. In Oklahoma (Mississippi Lime play) and Texas (Barnett and Eagle Ford Shales and Marble Falls play), both states where we have acquired substantial acreage positions, royalties are commonly in the 15-25% range, resulting in net revenue interests to us in the 75-85% range.

In the Texas Barnett and Eagle Ford Shales, Oklahoma Mississippi Lime and Appalachian Basin Marcellus and Utica plays, where horizontal wells are generally drilled on much larger drilling units (sometimes approaching 1,000 acres), the mineral and/or surface rights are generally acquired from multiple parties. In the case of "urban" drilling areas in the Barnett Shale, there may be as many as 3,500 royalty owners within a single drilling unit.

Because the acquisition of hydrocarbon leases in highly desirable basins is an extremely competitive process, and involves certain geological and business risks to identify prospective areas, leases are frequently held by other oil and gas operators. In order to access the rights to drill on those leases held by others, we may elect to farm-in lease rights and/or purchase assignments of leases from competitor operators. Typically, the assignor of such leases will reserve an overriding royalty interest (over and above the existing mineral owner royalty), that can range from 2-3% up to as high as 7 or 8%, and sometimes contain options to convert the overriding royalty interests to working interests at payout of a well. Areas where farm-ins are utilized can result in additional reductions in our net revenue interests, depending upon their terms and how much of a particular drilling unit the farm-in acreage encompasses.

There will be occasions where competitors owning leasehold interests in areas where we want to drill will not farm-out or sell their leases, but will instead join us as working interest partners, paying their proportionate share of all drilling and operating costs in a well. However, it is generally our goal to obtain 100% of the working interest in any and all new wells that we operate.

Contractual Revenue Arrangements

Natural Gas. We market the majority of our natural gas production to gas marketers directly or to third party plant operators who process and market the gas. The sales price of natural gas produced is a function of the market in the area and typically linked to a regional index. The pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline Zone 4 (200 Leg), Transco Leidy Line, Columbia Appalachia, NYMEX and Transco Zone 5;
- Mississippi Lime - Southern Star;
- Barnett Shale and Marble Falls- primarily Waha but with smaller amounts sold into a variety of north Texas outlets;
- Raton – ANR, Panhandle, and NGPL;
- Black Warrior Basin – Southern Natural;
- Eagle Ford – Transco Zone 1;
- Arkoma – Enable Gas; and
- Other regions - primarily the Texas Gas Zone SL spot market (New Albany Shale) and the Cheyenne Hub spot market (Niobrara).

We attempt to sell the majority of our natural gas at monthly, fixed index prices and a smaller portion at index daily prices.

Crude Oil. Crude oil produced from our wells flows directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. The crude oil is typically sold at the prevailing spot market price for each region, less appropriate trucking/pipeline charges. The oil and natural gas liquids production of our Rangely assets flows into a common carrier pipeline and is sold at prevailing market prices, less applicable transportation and oil quality differentials. We do not have delivery commitments for fixed and determinable quantities of crude oil in any future periods under existing contracts or agreements.

Natural Gas Liquids. NGLs are extracted from the natural gas stream by processing and fractionation plants enabling the remaining "dry" gas to meet pipeline specifications for transport or sale to end users or marketers operating on the receiving pipeline. The resulting plant residue natural gas is sold as described above and the NGLs are generally priced and sold using the Mont Belvieu (TX) or Conway (KS) regional processing indices. The cost to process and fractionate the NGLs from the gas stream is typically either a volumetric fee for the gas and liquids processed or a percentage retention by the processing and fractionation facility. We do not have delivery commitments for fixed and determinable quantities of NGLs in any future periods under existing contracts or agreements.

For the year ended December 31, 2015, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC accounted for approximately 21%, 15%, 11% and 11% of our total natural gas, oil, and NGL production revenues, respectively, with no other single customer accounting for more than 10% for this period.

Drilling Partnerships. We generally have funded a portion of our drilling activities through sponsorship of tax-advantaged Drilling Partnerships. In addition to providing capital for our drilling activities, our Drilling Partnerships are a source of fee-based revenues, which are not directly dependent on commodity prices. See "Partnership Management Business" for further discussion.

Natural Gas and Oil Hedging

We seek to provide greater stability in our cash flows through our use of financial hedges for our natural gas, oil and natural gas liquids production. The financial hedges may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures and options contracts with qualified counterparties. Financial hedges are contracts between ourselves and counterparties and do not require physical delivery of hydrocarbons. Financial hedges allow us to mitigate hydrocarbon price risk, and cash is settled to the extent there is a price difference between the hedge price and the actual NYMEX settlement price. Settlement typically occurs on a monthly basis, at the time in the future dictated within the hedge contract. Financial hedges executed in accordance with our secured credit facility do not require cash margin and are secured by our natural gas and oil properties. To assure that the financial instruments will be used solely for hedging price risks and not for speculative purposes, we have a management committee to assure that all financial trading is done in compliance with our hedging policies and procedures. We do not intend to contract for positions that we cannot offset with actual production.

Natural Gas Gathering Agreements

Virtually all natural gas produced is gathered through one or more pipeline systems before sale or delivery to a marketer or an interstate pipeline. A gathering fee can be charged for each gathering activity that is utilized and by each separate gatherer providing the service. Fees will vary depending on the distance the gas travels and whether additional services such as compression, blending, or contaminant removal are provided.

Barnett and Marble Falls production in Texas is gathered/processed by a variety of companies depending on the location of the production. As in the case of Appalachian and Mississippi Lime production, either a fee is charged for the gathering activity alone, or a gatherer/processor may provide a combination of services to include processing, fractionation and/or compression. In some instances, the market to which the gas is sold will deduct the third-party gathering fees from the proceeds payable and pay the third-party gatherers directly.

In Appalachia, we have gathering agreements with Laurel Mountain Midstream, LLC ("Laurel Mountain"). Under these agreements, we dedicate our natural gas production in certain areas within southwest Pennsylvania to Laurel Mountain for transportation to interstate pipeline systems or local distribution companies, subject to certain exceptions. In return, Laurel Mountain is required to accept and transport our dedicated natural gas subject to certain conditions. The greater of $0.35 per mcf or 16% of the gross sales price of the natural gas is charged by Laurel Mountain for the majority of the gas. A lesser fee does apply to a small number of specific wells in the area. We also use Anadarko Marcellus Midstream, L.L.C.'s facilities to gather our Lycoming Co., Pennsylvania production for a $0.45 MMBtu fee which delivers our production to Transco Interstate pipeline for purchase by Sequent Energy Management, L.P. Our Utica production in Ohio is gathered by both Utica East Ohio Midstream, L.L.C. ("UEO") and Blue Racer Midstream, L.L.C. for delivery to UEO's Kensington Processing plant. Residue gas is sold to markets on Dominion East Ohio or Tennessee pipelines. UEO markets the NGLs and returns proceeds to us.

In the Raton Basin (New Mexico and Colorado), we gather all of our production and deliver it to Colorado Interstate Gas Pipeline, an interstate pipeline. In the Black Warrior Basin (Alabama), we gather our own production and deliver it to the Southcross Alabama pipeline who then delivers the gas to our purchaser, Interconn Resources, L.L.C. and BP.

Mississippi Lime production is currently gathered, processed, fractionated, and marketed by one company, SemGas, and they return a Percent of Proceeds ("POP") of the revenues it receives. That POP amount is 95%. The remaining 5% and a $0.3276 MMBtu gathering fee are paid to SemGas for all services provided.

Availability of Energy Field Services

We contract for drilling rigs and purchase goods and services necessary for the drilling and completion of wells from a number of drillers and suppliers, none of which supplies a significant portion of our annual needs. Over the past year, we and other oil and natural gas companies have experienced a significant reduction in drilling and operating costs. We cannot predict the duration or stability of the current level of supply and demand for drilling rigs and other goods and services required for our operations with any certainty due to numerous factors affecting the energy industry, including the supply and demand for natural gas and oil.

We maintained a Pennsylvania Operating Services Agreement, pursuant to which a subsidiary of Chevron Corporation provided us (including Drilling Partnerships which we manage) with water disposal services with respect to certain wells in Pennsylvania in exchange for specified fees. We had an obligation to indemnify the provider against all claims and liabilities arising out of its provision of services under this agreement. On February 12, 2015, we received notice of termination from Chevron Corporation of the Pennsylvania Operating Services Agreement which terminated on August 12, 2015. Subsequent to the termination of the Pennsylvania Operating Services Agreement, we have utilized many of the same water hauling companies in the area but have had to pay higher disposal related fees.

Competition

The energy industry is intensely competitive in all of its aspects. We operate in a highly competitive environment for acquiring properties and other energy companies, attracting capital for our Drilling Partnerships, contracting for drilling equipment and securing trained personnel. We also compete with the exploration and production divisions of public utility companies for mineral property acquisitions. Competition is intense for the acquisition of leases considered favorable for the development of hydrocarbons in commercial quantities. Our competitors may be able to pay more for hydrocarbon properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Furthermore, competition arises not only from numerous domestic and foreign sources of hydrocarbons but also from other industries that supply alternative sources of energy. Product availability and price are the principal means of competition in selling natural gas, crude oil, and natural gas liquids.

Many of our competitors possess greater financial and other resources which may enable them to identify and acquire desirable properties and market their hydrocarbon production more effectively than we do. Moreover, we also compete with a number of other companies that offer interests in Drilling Partnerships. As a result, competition for investment capital to fund Drilling Partnerships is intense.

Markets

The availability of a ready market for natural gas, oil and natural gas liquids and the price obtained, depends upon numerous factors beyond our control, as described in “Item 1A: Risk Factors - Risks Relating to Our Business”. Product availability and price are the principal means of competition in selling natural gas, oil and NGLs.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot 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. In addition, seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in certain areas. These seasonal anomalies may pose challenges for meeting our well construction objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay our operations. We have in the past drilled a greater number of wells during the winter months, because we typically received the majority of funds from Drilling Partnerships during the fourth calendar quarter.

Environmental Matters and Regulation

Our operations relating to drilling and waste disposal are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As operators within the complex natural gas and oil industry, we must comply with laws and regulations at the federal, state and local levels. These laws and regulations can restrict or affect our business activities in many ways, such as by:

·

restricting the way waste disposal is handled;

- limiting or prohibiting drilling, construction and operating activities in sensitive areas such as wetlands, coastal regions, non-attainment areas, tribal lands or areas inhabited by threatened or endangered species;
- requiring the acquisition of various permits before the commencement of drilling;
- requiring the installation of expensive pollution control equipment and water treatment facilities;
- restricting the types, quantities and concentration of various substances that can be released into the environment in connection with siting, drilling, completion, production, and plugging activities;
- requiring remedial measures to reduce, mitigate and/or respond to releases of pollutants or hazardous substances from existing and former operations, such as pit closure and plugging of abandoned wells;

- enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations;
- imposing substantial liabilities for pollution resulting from operations; and
- requiring preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement with respect to operations affecting federal lands or leases.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where pollutants or wastes have been disposed or otherwise released. Neighboring landowners and other third parties can file claims for personal injury or property damage allegedly caused by noise and/or the release of pollutants or wastes into the environment. These laws, rules and regulations may also restrict the rate of natural gas and oil production below the rate that would otherwise be possible. The regulatory burden on the natural gas and oil industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently enact new, and revise existing, environmental laws and regulations, and any new laws or changes to existing laws that result in more stringent and costly waste handling, disposal and clean-up requirements for the natural gas and oil industry could have a significant impact on our operating costs.

We believe that our operations are in substantial compliance with applicable environmental laws and regulations, and compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, we cannot assure future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs.

Environmental laws and regulations that could have a material impact on our operations include the following:

National Environmental Policy Act. Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, or “NEPA.” NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly affect the environment. In the course of such evaluations, an agency will typically require an Environmental Assessment to assess the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that will be made available for public review and comment. All of our proposed exploration and production activities on federal lands, if any, require governmental permits, many of which are subject to the requirements of NEPA. This process has the potential to delay the development of natural gas and oil projects.

Waste Handling. The Solid Waste Disposal Act, including RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” and the disposal of non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency (the “EPA”), individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development and production of crude oil and natural gas constitute “solid wastes,” which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as solid waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

We believe that our operations are currently in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that they hold all necessary and up-to-date permits, registrations and other authorizations to the extent that they are required under such laws and regulations. Although we and our subsidiaries do not believe the current costs of managing wastes to be significant, any more stringent regulation of natural gas and oil exploitation and production wastes could increase the costs to manage and dispose of such wastes.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes joint and several liability, without regard to fault or legality of conduct, on persons who are considered under the statute to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Our operations are, in many cases, conducted at properties that have been used for natural gas and oil exploitation and production for many years. Although we believe that we utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us or on or under other locations, including off-site locations, where such substances have been taken for disposal. There may be evidence that petroleum spills or releases have occurred at some of the properties owned or leased by us. However, none of these spills or releases appears to be material to our financial condition and we believe all of them have been or will be appropriately remediated. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties, and the substances disposed or released on them, may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including waste disposed of by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, the federal regulations that implement the Clean Water Act, and analogous state laws and regulations impose restrictions and strict controls on the discharge of pollutants, including produced waters and other natural gas and oil wastes, into navigable waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the relevant state. These permits may require pretreatment of produced waters before discharge. Compliance with such permits and requirements may be costly. Further, much of our natural gas extraction activity utilizes a process called hydraulic fracturing, which results in water discharges that must be treated and disposed of in accordance with applicable regulatory requirements.

On April 21, 2014, the U.S. Army Corps of Engineers ("USACE") and the EPA proposed a rule that would define 'Waters of the United States' ("WOTUS"), i.e., the scope of waters protected under the Clean Water Act, in light of several U.S. Supreme Court opinions (U.S. v. Riverside Bayview, Rapanos v. United States, and Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers). The public comment period concluded on November 14, 2014 and the EPA received hundreds of thousands of comments on the proposed rule. On May 27, 2015, the EPA and USACE announced the final rule redefining the extent of the agencies' jurisdiction over WOTUS, and the final rule was published in the Federal Register on June 29, 2015 with an effective date of August 28, 2015. The final rule was immediately challenged by multiple parties, including individual states, in both United States District Courts and U.S. Circuit Courts of Appeals. On October 9, 2015, the 6th Circuit Court of Appeals found that the petitioners, totaling 18 states, demonstrated a "substantial possibility of success on the merits of the claim" and issued a nationwide stay of the WOTUS final rule. Currently, this nationwide stay is in place and the litigation in both the U.S. District and Circuit Courts is ongoing. Additionally, there have been legislative efforts by the General Assembly to nullify the rule, specifically a joint resolution of Congress passed under authority of the Congressional Review Act that was vetoed by President Obama on January 19, 2016. As drafted, the final rule is broader in scope then the current rule, and will increase the costs of compliance and result in additional permitting requirements for some of our existing or future facilities.

The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The Clean Water Act also requires specified facilities to maintain and implement spill prevention, control and countermeasure plans and to take measures to minimize the risks of petroleum spills. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for failure to obtain or non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. We believe that our operations are in substantial compliance with the requirements of the Clean Water Act.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, the federal regulations that implement the Clean Air Act, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including drilling sites, processing plants, certain storage vessels and compressor stations, and also impose various monitoring and reporting requirements. These laws and regulations also apply to entities that use natural gas as fuel, and may increase the costs of customer compliance to the point where demand for natural gas is affected. Such laws and regulations may require obtaining pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions. Air permits contain various emissions and operational limitations, and may require specific emission control technologies to limit emissions. Various air quality regulations are periodically reviewed by the EPA and are amended as deemed necessary. The EPA may also issue new regulations based on changing environmental concerns.

Recent revisions to federal Clean Air Act rules impose additional emissions control requirements and practices on our operations. Some of our new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to comply with new or revised requirements. These regulations may increase the costs of compliance for some facilities. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We believe that our operations are in substantial compliance with the requirements of the Clean Air Act and comparable state laws and regulations.

While we will likely be required to incur certain capital expenditures in the future for air pollution control equipment to comply with applicable regulations and to obtain and maintain operating permits and approvals for air emissions, we believe that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than other similarly situated companies.

OSHA and Other Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act, or “OSHA,” and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

On October 22, 2015, the EPA responded to an October 24, 2012 petition to the EPA requesting that the oil and gas extraction industrial sector be added to the sectors with reporting requirements covered by Section 313 of the Emergency Planning and Community Right-to-Know Act (the Toxics Release Inventory or “TRI”). In its response, the EPA stated that it intends to propose a rulemaking that would subject natural gas processing facilities that employ more than 10 people to annual TRI reporting, but that the EPA will not propose that well sites, compressor stations, pipelines, and other oil and gas extraction industrial sector facilities be subject to TRI reporting.

Additionally, the White House Office of Management and Budget received OSHA’s final “Occupational Exposure to Crystalline Silica” rule on December 21, 2015. The final rule has not been published, but is expected to follow OSHA’s proposed rule from September 12, 2013 that would impose a new exposure limit for silica and with it various new requirements. The federal 2015 Fall Unified Agenda and Regulatory Plan lists February 2016 as the target release date for the final rulemaking. OSHA has previously addressed respirable silica from the oil and gas industry operations back in December 2014 when it released a “Hydraulic Fracturing and Flowback Hazards Other than Respirable Silica” safety alert. If finalized, the rule would likely result in significant costs for the oil and gas industry to comply with the new requirements.

Greenhouse Gas Regulation and Climate Change. To date, legislative and regulatory initiatives relating to greenhouse gas emissions have not had a material impact on our business. However, Congress has been actively considering climate change legislation. More directly, the EPA has begun regulating greenhouse gas emissions under the federal Clean Air Act. In response to the Supreme Court’s decision in Massachusetts v. EPA, 549 U.S. 497 (2007) (holding that greenhouse gases are air pollutants covered by the Clean Air Act), the EPA made a final determination that greenhouse gases endangered public health and welfare, 74 Fed. Reg. 66,496 (Dec. 15, 2009). This finding led to the regulation of greenhouse gases under the Clean Air Act. Currently, the EPA has promulgated two final rules relating to greenhouse gases that will affect our businesses.

First, the EPA promulgated the so-called “Tailoring Rule” which established emission thresholds for greenhouse gases under the Clean Air Act permitting programs, 75 Fed. Reg. 31,514 (June 3, 2010). Both the federal preconstruction review program, known as “Prevention of Significant Deterioration” (“PSD”), and the operating permit program are now implicated by emissions of greenhouse gases. These programs, as modified by the Tailoring Rule, could require some new facilities to obtain a PSD permit depending on the size of the new facilities. In addition, existing facilities as well as new facilities that exceed the emissions thresholds could be required to obtain the requisite operating permits.

On June 23, 2014, the United States Supreme Court ruled on challenges to the Tailoring Rule in the case of Utility Air Regulatory Group v. EPA, 134 S. Ct. 2427 (2014). The Court limited the applicability of the PSD program and Tailoring Rule to only new sources or modifications that would trigger PSD for another criteria pollutant such that projects cannot trigger PSD based solely on greenhouse gas emissions. However, if PSD is triggered for another pollutant, greenhouse gases could be subject to a control technology review process. The Court’s decision also means that sources cannot trigger a federal operating permit requirement based solely on greenhouse gas emissions. Overall, the impact of the Tailoring Rule after the Court’s decision is that it is unlikely to have much, if any, impact on our operations. However, the EPA is still in the process of responding to the Court’s decision through rulemakings.

Second, the EPA finalized its Mandatory Reporting of Greenhouse Gases rule in 2009, 74 Fed. Reg. 56,260 (Oct. 2009). Subsequent revisions, additions and clarifications were promulgated, including a rule subpart specifically addressing the natural gas industry. This particular subpart was most recently revised in October 2015, 80 Fed. Reg. 64262 (Oct. 22, 2015), when the EPA finalized changes to calculation methods, monitoring and data reporting requirements, and other provisions. Shortly thereafter, in January 2016, the EPA proposed additional revisions to the broader Greenhouse Gas Reporting for public comment. In general, the Greenhouse Gas Reporting Rule requires certain industry sectors that emit greenhouse gases above a specified threshold to report greenhouse gas emissions to the EPA on an annual basis. The natural gas industry is covered by the rule and requires annual greenhouse gas emissions to be reported by March 31 of each year for the emissions during the preceding calendar year. This rule imposes additional obligations on us to determine whether the greenhouse gas reporting applies and if so, to calculate and report greenhouse gas emissions.

In addition to these existing rules, the Obama Administration announced in January 2015 that it was developing additional rules to curb greenhouse gas emissions from the oil and gas sector, as part of a new national strategy for reducing methane emissions from the sector by 40 – 45% from 2012 levels by the year 2025. This national methane reduction strategy targeting the oil and gas sector is related to the Obama Administration’s broader Climate Action Plan of 2013. Multiple federal agencies, including the EPA and the U.S. Department of the Interior’s Bureau of Land Management, which we refer to as the BLM, are involved in implementing the national methane reduction strategy.

In August 2015, the EPA proposed a broad suite of regulatory measures to implement the national methane reduction strategy, as well as to reduce emissions of ozone-forming volatile organic compounds (“VOCs”) and clarify air permitting requirements for the oil and gas sector. The proposed measures include: (1) a revised New Source Performance Standards (“NSPS”) rule for oil and natural gas production, transmission, and distribution that would expand existing requirements for sources of VOCs and establish new requirements for sources of methane; (2) draft Control Techniques Guidelines that direct states to adopt regulations for reducing VOC emissions from existing oil and gas facilities in certain ozone nonattainment areas and states in the Ozone Transport Region; (3) a Federal Implementation Plan for certain oil and gas operations located in Indian country; and (4) a rule defining the circumstances in which oil and gas equipment and activities are to be considered part of a source that is subject to “major source” permitting requirements under the Clean Air Act. The EPA accepted public comments on these proposals through early December 2015. The proposals are expected to be finalized in 2016.

Consistent with the Obama Administration’s methane reduction strategy, on January 22, 2016, BLM released a proposed rule to update standards for venting, flaring, and equipment leaks from oil and gas production activities on onshore Federal and Indian leases. BLM’s existing requirements are more than three decades old. According to BLM, the proposed rule would ensure that operators use modern best practices to minimize waste of produced natural gas and reduce emissions of methane and VOCs.

There are also ongoing legislative and regulatory efforts to encourage the use of cleaner energy technologies. While natural gas is a fossil fuel, it is considered to be more benign, from a greenhouse gas standpoint, than other carbon-based fuels, such as coal or oil. Thus, future regulatory developments could have a positive impact on our business to the extent that they either decrease the demand for other carbon-based fuels or position natural gas as a favored fuel.

In addition to domestic regulatory developments, the United States is a participant in multi-national discussions intended to deal with the greenhouse gas issue on a global basis. To date, those discussions have not resulted in the imposition of any specific regulatory system, but such talks are continuing and may result in treaties or other multi-national agreements (e.g., the “Paris Agreement,” reached at the United Nations Conference on Climate Change in December 2015) that could have an impact on our business.

Finally, the scientific community continues to engage in a healthy debate as to the impact of greenhouse gas emissions on planetary conditions. For example, such emissions may be responsible for increasing global temperatures, and/or enhancing the frequency and severity of storms, flooding and other similar adverse weather conditions. We do not believe that these conditions are having any material current adverse impact on our business, and we are unable to predict at this time, what, if any, long-term impact such climate effects would have.

Energy Policy Act. Much of our natural gas extraction activity utilizes a process called hydraulic fracturing. The Energy Policy Act of 2005 amended the definition of “underground injection” in the Federal Safe Drinking Water Act of 1974, or “SDWA.” This amendment effectively excluded hydraulic fracturing for oil, gas or geothermal activities from the SDWA permitting requirements, except when “diesel fuels” are used in the hydraulic fracturing operations. Recently, this subject has received much regulatory and legislative attention at both the federal and state level and we anticipate that the permitting and compliance requirements applicable to hydraulic fracturing activity are likely to become more stringent and could have a material adverse impact on our business and operations. For instance, the EPA released its revised final guidance document on SDWA underground injection control permitting for hydraulic fracturing using diesel fuels in February 2014, along with responses to selected substantive public comments on the EPA’s previous draft guidance, a fact sheet and a memorandum to the EPA's regional offices regarding implementation of the guidance. The process for implementing the EPA's final guidance document may vary across states depending on the regulatory authority responsible for implementing the SDWA UIC program in each state.

The U.S. Senate and House of Representatives considered legislative bills in the 111th, 112th, and 113th Sessions of Congress that, if enacted, would have repealed the SDWA permitting exemption for hydraulic fracturing activities. Titled the "Fracturing Responsibility and Awareness of Chemicals Act," or "Frac Act," the legislative bills as proposed could have potentially led to significant oversight of hydraulic fracturing activities by federal and state agencies. The Frac Act was re-introduced in the current 114th Session of Congress and referred to the Committee on Environment and Public Works; if enacted into law, the legislation as proposed could potentially result in significant regulatory oversight, which may include additional permitting, monitoring, recording and recordkeeping requirements for us.

We believe our operations are in substantial compliance with existing SDWA requirements. However, future compliance with the SDWA could result in additional requirements and costs due to the possibility that new or amended laws, regulations or policies could be implemented or enacted in the future.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans and can result in death. We conduct our natural gas extraction activities in certain formations where hydrogen sulfide may be, or is known to be, present. We employ numerous safety precautions at our operations to ensure the safety of our employees. There are various federal and state environmental and safety requirements for handling sour gas, and we are in substantial compliance with all such requirements.

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

State Regulation and Taxation of Drilling. The various states regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Pennsylvania has imposed an impact fee on wells drilled into an unconventional formation, which includes the Marcellus Shale. The impact fee, which changes from year to year, is based on the average annual price of natural gas as determined by the NYMEX price, as reported by the Wall Street Journal for the last trading day of each calendar month. For example, based upon natural gas prices for 2015, the impact fee for qualifying unconventional horizontal wells spudded during 2015 was $45,300 per well, while the impact fee for unconventional vertical wells was $9,100 per well. The payment structure for the impact fee makes the fee due the year after an unconventional well is spudded, and the fee will continue for 15 years for an unconventional horizontal well and 10 years for an unconventional vertical well. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources.

States may regulate rates of production and may establish maximum limits on daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, the type of wells that may be drilled in the future in proximity to existing wells and to limit the number of wells or locations from which we can drill. Texas imposes a 7.5% tax on the market value of natural gas sold, 4.6% on the market value of condensate and oil produced and an oil field clean up regulatory fee of $0.000667 per Mcf of gas produced, a regulatory tax of $.001875 and the oil field clean-up fee of $.00625 per barrel of crude. New Mexico imposes, among other taxes, a severance tax of up to 3.75% of the value of oil and gas produced, a conservation tax of up to 0.24% of the oil and gas sold, and a school emergency tax of up to 3.15% for oil and 4% for gas. Alabama imposes a production tax of up to 2% on oil or gas and a privilege tax of up to 8% on oil or gas. Oklahoma imposes a gross production tax of 7% per Bbl of oil, up to 7% per Mcf of natural gas and a petroleum excise tax of .095% on the gross production of oil and gas.

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

Oil Spills and Hydraulic Fracturing. The Oil Pollution Act of 1990, as amended ("OPA"), contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

A number of federal agencies, including the EPA and the Department of Interior, are currently evaluating a variety of environmental issues related to hydraulic fracturing. For example, the EPA is conducting a study that evaluates any potential effects of hydraulic fracturing on drinking water and ground water. On December 9, 2013, the EPA's Hydraulic Fracturing Study Technical Roundtable of subject-matter experts from a variety of stakeholder groups met to discuss the work underway to answer the hydraulic fracturing study's key research questions. Individual research projects associated with the EPA's study were published in July 2014. On June 4, 2015, the EPA released its draft "Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources" (the "Draft Assessment"), in addition to nine new peer-reviewed scientific reports that formed the basis for certain findings included in the Draft Assessment. The scope of the Draft Assessment focuses on potential impacts to drinking water resources by hydraulic fracturing, specifically the following water activities that the EPA has identified as the "hydraulic fracturing water cycle" in the Draft Assessment: water acquisition from ground or surface waters; chemical mixing at the well site; well injection of hydraulic fracturing fluids; the collection and handling of wastewater from hydraulic fracturing (such as flowback and produced water); and wastewater treatment and waste disposal. The EPA revealed in its Draft Assessment that it has not found any evidence that hydraulic fracturing activities are performed in a way that leads to widespread, systemic impacts on drinking water resources. The EPA did identify specific instances where hydraulic fracturing activities may have led to impacts to drinking water; however, the EPA noted that those instances are minimal when compared to the number of hydraulically fractured wells in the United States. Notice of the Draft Assessment was published in the June 5, 2015 Federal Register, and several public teleconference calls and a public meeting were held by the EPA's Science Advisory Board (SAB) to discuss the Draft Assessment. On January 7, 2016, the SAB released a Draft Review of the EPA's Draft Assessment. The Draft Review includes many recommendations to the EPA that SAB believes the EPA should consider to improve the Draft Assessment. These recommendations include, but are not limited to: revising its draft finding that the EPA found no "evidence that hydraulic fracturing mechanisms have led to widespread, systemic impacts on drinking water resources," as the SAB found the statement to be ambiguous and therefore require clarification and additional explanation; adding further discussion on the Pavillion, Wyoming; Parker County, Texas; and Dimock, Pennsylvania investigations; collecting and add new data regarding the chemicals used during hydraulic fracturing and the content of flowback water; and adding Best Management Practices and suggested improvements to each stage of the hydraulic fracturing process.

BLM proposed a rule on May 11, 2012 that includes provisions requiring disclosure of chemicals used in hydraulic fracturing and construction standards for hydraulic fracturing on federal lands. On May 24, 2013, BLM published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands. On March 26, 2015, BLM issued a final rule updating the regulations governing hydraulic fracturing on federal and Indian lands. Among the many new requirements, the final rule requires operators planning to conduct hydraulic fracturing to design and implement a casing and cementing program that follows best practices and meets performance standards to protect and isolate usable water, as well as requires operators to monitor cementing operations during well completion. Additionally, the final rule requires that companies publicly disclose the chemicals used in the hydraulic fracturing process, subject to limited exceptions for trade secret materials; comply with safety standards for storage of produced water in rigid enclosed, covered, or netted and screened above-ground tanks, with very limited exceptions allowing use of pits that must be approved by BLM on a case-by-case basis; and submit detailed information to the BLM on proposed operations, including but not limited to well geology, location of faults and fractures, estimated volume of fluid to be used, and estimated direction and length of fractures. The final rule also provides that for certain circumstances in which specific state or tribal regulations are equally or more protective than the BLM's new rules, the state or tribe may obtain a variance for that specific regulation. The final rule was set to go into effect on June 24, 2015. However on June 23, 2015, the U.S. District Court for the District of Wyoming announced a stay on the effective date of the rule in State of Wyoming v. Dep't of Interior, No. 2:15-cv-00043, a lawsuit that involves several states and industry associations who requested that the Court grant a preliminary injunction of the final rule. On September 30, 2015, the U.S. District Court granted the preliminary injunction, thus enjoining the final rule.

In addition, state and local conservancy districts and river basin commissions have all previously exercised their various regulatory powers to curtail and, in some cases, place moratoriums on hydraulic fracturing. State regulations include express inclusion of hydraulic fracturing into existing regulations covering other aspects of exploration and production and specifically may include, but not be limited to, the following:

- requirement that logs and pressure test results are included in disclosures to state authorities;
- disclosure of hydraulic fracturing fluids and chemicals, potentially subject to trade secret/confidential proprietary information protections, and the ratios of same used in operations;
- specific disposal regimens for hydraulic fracturing fluids;

- replacement/remediation of contaminated water assets; and
- minimum depth of hydraulic fracturing.

Local regulations, which may be preempted by state and federal regulations, have included, but have not been limited to, the following, which may extend to all operations including those beyond hydraulic fracturing:

- noise control ordinances;
- traffic control ordinances;
- limitations on the hours of operations; and
- mandatory reporting of accidents, spills and pressure test failures.

Other Regulation of the Natural Gas and Oil Industry. The natural gas and oil industry is extensively regulated by federal, state and local authorities. Legislation affecting the natural gas and oil industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on the industry. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in their industries with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the potential costs to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Employees

We do not directly employ any of the persons responsible for our management or operation. In general, personnel employed by ATLS manage and operate our business. As of December 31, 2015, approximately 619 ATLS employees provided direct support to our operations. After the closing of the Atlas Energy Merger, all of our personnel were employed by our general partner. Some of the officers of our general partner may spend a substantial amount of time managing the business and affairs of our general partner and its affiliates other than us and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

Available Information

We make our periodic reports under the Securities Exchange Act of 1934, including our annual report on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K, and any amendments to those reports, available through our website at www.atlasresourcepartners.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (“SEC”). To view these reports, click on “Investor Relations”, then “SEC Filings”. The other information contained on or hyperlinked from our website does not constitute part of this report. You may also receive, without charge, a paper copy of any such filings by request to us at Park Place Corporate Center One, 1000 Commerce Drive, Suite 400, Pittsburgh, Pennsylvania 15275, telephone number (800) 251-0171. A complete list of our filings is available on the SEC’s website at www.sec.gov. Any of our filings are also available at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information.

27

ITEM 1A: RISK FACTORS

You should carefully consider each of the following risks, which we believe are the principal risks that we face and of which we are currently aware, and all of the other information in this report. Some of the risks described below relate to our business, while others relate principally to the securities markets and ownership of our limited partnership interests. Partnership interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. The risks and uncertainties our company faces are not limited to those set forth in the risk factors described below. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business. In addition, past financial performance may not be a reliable indicator of future performance, and historical trends should not be used to anticipate results or trends in future periods. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Risks Relating to Our Business

Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and oil, which have declined substantially. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Continued depressed prices in the future would have a negative impact on our future financial results and could result in an impairment charge. Because our reserves are predominantly natural gas, changes in natural gas prices have a more significant impact on our financial results.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include but are not limited to the following:

- the levels and location of natural gas and oil supply and demand and expectations regarding supply and demand, including the potential long-term impact of an abundance of natural gas and oil (such as that produced from our Marcellus Shale properties) on the domestic and global natural gas and oil supply;
- the level of industrial and consumer product demand;
- weather conditions;
- fluctuating seasonal demand;
- political conditions or hostilities in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level of foreign imports;
- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;

- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall economic conditions, including the value of the U.S. dollar relative to other major currencies.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. In the past, the prices of natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue. During the year ended December 31, 2015, the NYMEX Henry Hub natural gas index price ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $61.43 per Bbl to a low of $34.73 per Bbl. Between January 1, 2016 and February 29, 2016, the NYMEX Henry Hub natural gas index price ranged from a high of $2.47 per MMBtu to a low of $1.71 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $36.76 per Bbl to a low of $26.21 per Bbl.

A continuation of the prolonged substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition, results of operations, and ability to continue cash distributions to unitholders. We may use various derivative instruments in connection with anticipated oil and natural gas sales to reduce the impact of commodity price fluctuations. However, the entire exposure of our operations from commodity price volatility is not currently hedged, and we may not be able to hedge such exposure going forward. To the extent we do not hedge against commodity price volatility, or our hedges are not effective, our results of operations and financial position may be further diminished.

In addition, low oil and natural gas prices have reduced, and may in the future further reduce, the amount of oil and natural gas that can be produced economically by our operators. This scenario may result in our having to make substantial downward adjustments to our estimated proved reserves, which could negatively impact our borrowing base and our ability to fund our operations. If this occurs or if production estimates change or exploration or development results deteriorate, successful efforts method of accounting principles may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Our operators could also determine during periods of low commodity prices to shut in or curtail production from wells on our properties. In addition, they could determine during periods of low commodity prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices.

Oil prices and natural gas prices have declined substantially from historical highs and may remain depressed for the foreseeable future. Approximately 17% of our 2015 total revenues were derived from oil and condensate sales. Approximately 81% of our 2015 total production was natural gas, on a “Mcf-equivalent” basis. Any additional decreases in prices of oil and natural gas may adversely affect our cash generated from operations, results of operations, financial position, and our ability to pay distributions, perhaps materially.

During the year ended December 2015, the spot WTI market price at Cushing, Oklahoma has declined from a high of $61.43 per Bbl to a low of $34.73 per Bbl. During the nine years prior to December 31, 2015, natural gas prices at Henry Hub have ranged from a high of $13.31 per MMBtu in 2008 to a low of $1.76 per MMBtu in 2015. Between January 1, 2015 and December 31, 2015, the Henry Hub spot market price of natural gas ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu. The reduction in prices has been caused by many factors, including substantial increases in U.S. oil and natural gas production and reserves from unconventional (shale) reservoirs, without an offsetting increase in demand. The International Energy Agency (“IEA”) forecasts steady or a slightly declining U.S. production growth and a slowdown in global demand growth in 2016.

This environment could cause the prices for oil and natural gas to remain at current levels or to fall to even lower levels. If prices for oil and natural gas continue to remain depressed for lengthy periods, we may be required to write down the value of our oil and natural gas properties, and some of our undeveloped locations may no longer be economically viable. In addition, sustained low prices for oil and natural gas will negatively impact the value of our estimated proved reserves and the amount that we are allowed to borrow under our bank credit facility (as a result of borrowing base redeterminations) and reduce the amounts of cash we would otherwise have available to pay expenses, fund capital expenditures, make distributions to our unitholders, and service our indebtedness.

Competition in the natural gas and oil industry is intense, which may hinder our ability to acquire natural gas and oil properties and companies and to obtain capital, contract for drilling equipment and secure trained personnel.

We operate in a highly competitive environment for acquiring properties and other natural gas and oil companies, attracting capital through our Drilling Partnerships, contracting for drilling equipment and securing trained personnel. Our competitors may be able to pay more for natural gas, natural gas liquids and oil properties and drilling equipment and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Moreover, our competitors for investment capital may have better track records in their programs, lower costs or stronger relationships with participants in the oil and gas investment community than we do. All of these challenges could make it more difficult for us to execute our growth strategy. We may not be able to compete successfully in the future in acquiring leasehold acreage or prospective reserves or in raising additional capital.

Furthermore, competition arises not only from numerous domestic and foreign sources of natural gas and oil but also from other industries that supply alternative sources of energy. Competition is intense for the acquisition of leases considered favorable for the development of natural gas and oil in commercial quantities. Product availability and price are the principal means of competition in selling natural gas and oil. Many of our competitors possess greater financial and other resources than we do, which may enable them to identify and acquire desirable properties and market their natural gas and oil production more effectively than we can.

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

Our key operated project areas are located in active drilling areas in the Mississippi Lime, Marble Falls, Utica Shale and Marcellus Shale, and many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of natural gas and oil in these areas.

Our operations require liquidity for normal operating expenses, servicing our debt, capital expenditures and distributions to our limited partners and general partners.

Our primary liquidity requirements, in addition to normal operating expenses, are for servicing our debt, capital expenditures and distributions to our limited partners and general partner. In general, we expect to fund our liquidity needs through cash flow from operations (including our hedges), bank borrowings, the Drilling Partnerships and equity and debt offerings. Due to the steep decline in commodity prices, our ability to obtain funding in the equity or capital markets has been, and may continue to be, constrained, and there can be no assurances that our liquidity requirements will continue to be satisfied given current commodity prices. If our sources of liquidity are not sufficient to fund our current or future liquidity needs, including as a result of any future borrowing base redetermination, we may be required to take other actions, such as:

- refinancing, restructuring or reorganizing all or a portion of our debt or capital structure;
- obtaining alternative financing;
- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital;
- liquidating all or a portion of our hedge portfolio;
- seeking additional partners to develop our assets;
- reducing our planned capital program;
- continuing to take, and potentially increasing, our cost saving measures to reduce costs, including renegotiation contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs; or
- revising or delaying our other strategic plans.

Our ability to take these actions will depend on, among other things, the conditions of the capital markets and our financial condition at such time. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable as the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide any new funding. We cannot assure you that we would be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that would be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions would allow us to meet our debt obligations and capital requirements.

We are currently primarily dependent on our credit facilities for liquidity. Any further reduction of the borrowing base under our revolving credit facility could reduce or eliminate our ability to borrow under the facility and may require us to repay indebtedness under our credit facilities earlier than anticipated, which would adversely impact our liquidity.

Subject to amounts reserved in the discretion of our Board of Directors to provide for the proper conduct of our business, our limited partnership agreement provides that we make distributions to our unitholders of available cash. Therefore, we have not historically accumulated cash to preserve liquidity and have been dependent on the capital markets and our credit facilities for liquidity. Although our Board of Directors approved a reduction of our common unit distributions, if the constrained capital markets conditions continue, we will continue to be primarily reliant on our credit facilities, and to the extent available, the excess of net cash provided by operating activities, for liquidity.

At December 31, 2015, there was approximately $103.8 million of available borrowing capacity under our revolving credit facility. The revolving credit facility is subject to semi-annual redeterminations of its borrowing base, based primarily on reserve reports, and our next redetermination date is in May 2016. Downward revisions of our oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant. For example, as a result of lower commodity prices, in November 2015, the borrowing base decreased from $750 million to $700 million. Continued low commodity prices and the possible reserve write-downs that may result, along with the maturity schedule of our hedges, may impact future redeterminations.

There can be no assurance that our lenders will not reduce the borrowing base to an amount below our outstanding borrowings, which would require us to repay a portion of outstanding borrowings or deposit additional collateral to eliminate such deficiency. In such event, we may be required to enter into discussions with our lenders or take other actions, including those described in the preceding risk factor, to satisfy our obligations as a result of such a borrowing base redetermination. If we cannot make the required payments under our credit facilities, including as a result of a borrowing base redetermination to an amount below our outstanding borrowings, or the indentures governing our senior notes, an event of default would result thereunder as well as a cross-default under our other debt agreements. Upon the occurrence of an event of default, the lenders under our credit facilities or holders or our notes, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged a significant portion of our assets as collateral under our credit facilities. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facilities and our other liabilities.

Our operations require substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our asset base will decline, which could cause our revenues to decline and affect our ability to pay distributions on our units.

The natural gas and oil industry is capital intensive. If we are unable to obtain sufficient capital funds on satisfactory terms, we may be unable to increase or maintain our inventory of properties and reserve base, or be forced to curtail drilling or other activities. This could cause our revenues to decline and diminish our ability to service any debt that we may have at such time. If we do not make sufficient or effective expansion capital expenditures, including with funds from third-party sources, we will be unable to expand our business operations, and may not generate sufficient revenue or have sufficient available cash to pay distributions on our units.

Economic conditions and instability in the financial markets could negatively impact our business which, in turn, could impact the cash we have to make distributions to our unitholders.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the Chinese economy, and the United States real estate market have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and could lead to a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids produced from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and potential cash available for distribution.

The above factors can also cause volatility in the markets and affect our ability to raise capital and reduce the amount of cash available to fund operations. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. Disruptions in the capital and credit markets could negatively impact our access to liquidity needed for our businesses and impact flexibility to react to changing economic and business conditions. We may be unable to execute our growth strategies, take advantage of business opportunities, respond to competitive pressures or service our debt, any of which could negatively impact our business.

A continuing or weakening of the current economic situation could have an adverse impact on producers, key suppliers or other customers, or on our lenders, causing them to fail to meet their obligations. Market conditions could also impact our derivative instruments. If a counterparty is unable to perform its obligations and the derivative instrument is terminated, our cash flow and ability to pay distributions could be impacted which in turn could affect the amount of distributions that we are able to make to our unitholders. The uncertainty and volatility surrounding the global financial system may have further impacts on our business and financial condition that we currently cannot predict or anticipate.

Our debt obligations could restrict our ability to pay cash distributions and have a negative impact on our financing options and liquidity position.

Our debt obligations could have important consequences to us and our investors, including:

- requiring a substantial portion of our cash flow to make interest payments on this debt;
- making it more difficult to satisfy debt service and other obligations;
- increasing the risk of a future credit ratings downgrade of our debt, which could increase future debt costs and limit the future availability of debt financing;
- increasing our vulnerability to general adverse economic and industry conditions;
- reducing the cash flow available to fund capital expenditures and other corporate purposes and to grow our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry;
- placing us at a competitive disadvantage relative to our competitors that may not be as leveraged with debt;
- limiting our ability to borrow additional funds as needed or take advantage of business opportunities as they arise; and
- limiting our ability to pay cash distributions.

To the extent that we incur additional indebtedness, the risks described above could increase.

Covenants in our debt documents restrict our business in many ways.

Our credit facilities and the indentures governing our senior notes contain various restrictive covenants that limit our ability to, among other things:

- incur additional debt or liens or provide guarantees in respect of obligations of other persons;
- pay distributions or redeem or repurchase our securities;
- prepay, redeem or repurchase debt;
- make loans, investments and acquisitions;
- enter into hedging arrangements;
- sell assets;
- enter into certain transactions with affiliates; and
- consolidate or merge with or into, or sell substantially all of our assets to, another person.

In addition, our debt documents require us to maintain specified financial ratios. Our ability to meet those financial ratios can be affected by events beyond our control, and we may be unable to meet those tests.

If we are unable to meet any of the covenants in our credit facilities or the indentures governing our senior notes, we may be required to enter into discussions with our lenders or take other actions, such as: refinancing, restructuring or reorganizing all or a portion of our debt or capital structure; obtaining alternative financing; selling assets; reducing or delaying capital investments; seeking to raise additional capital; liquidating all or a portion of our hedge portfolio; reducing our planned capital program; continuing to take, and potentially increasing, our cost saving measures to reduce costs, including renegotiation contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs; or revising or delaying our other strategic plans, which may negatively impact the price of our securities. A breach of any of the covenants in our credit facilities or the indentures governing our senior notes, respectively, could result in an event of default thereunder as well as a cross-default under our other debt agreements. Upon the occurrence of an event of default, the lenders under our credit facilities or holders or our notes, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged a significant portion of our assets as collateral under our credit facilities. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facilities and our other liabilities. Our borrowings under our credit facilities are, and are expected to continue to be, at variable rates of interest and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same.

Our cash distribution policy limits our ability to grow.

Because we distribute our available cash, if any, rather than reinvesting it in our business, our growth may not be as significant as businesses that reinvest their available cash to expand ongoing operations, and we may not have enough cash to meet our needs if any of the following events occur:

- an increase in our operating expenses;
- an increase in general and administrative expenses;
- an increase in principal and interest payments on our outstanding debt;
- a reduction in the amount we are allowed to borrow under our bank credit facility (including as a result of borrowing base redeterminations); or
- an increase in working capital requirements.

If we issue additional units or incur debt to fund our operations, acquisitions and expansion or investment capital expenditures, the payment of distributions on those additional units or interest on that debt could increase the risk that we will be unable to maintain or continue our per unit distribution level.

Significant physical effects of climate change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate-related damages to our facilities or our costs of operation potentially rising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

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

We market the majority of our natural gas production to gas utility companies, gas marketers, local distribution companies and industrial or other end-users. Crude oil produced from our wells flow directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. Natural gas liquids are extracted from the natural gas stream by processing and fractionation plants enabling the remaining “dry” gas (low Btu content) to meet pipeline specifications for transport to end users or marketers operating on the receiving pipeline. For the year ended December 31, 2015, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC accounted for approximately 21%, 15%, 11% and 11% of our total natural gas, crude oil and natural gas liquids production revenue, respectively, with no other single customer accounting for more than 10% for this period. To the extent these and other key customers reduce the amount of natural gas, crude oil and natural gas liquids they purchase from us, our revenues and cash available for distributions to unitholders could temporarily decline in the event we are unable to sell to additional purchasers.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price that we receive for our production could significantly reduce our cash available for distribution and adversely affect our financial condition.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price that we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead price that we receive could significantly reduce our cash available for distribution to our unitholders and adversely affect our financial condition. We use the relevant benchmark price to calculate our hedge positions, and we do not have any commodity derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials, which could adversely affect our results of operations.

Some of our undeveloped leasehold acreage is subject to leases that may expire in the near future.

As of December 31, 2015, leases covering approximately 4,702 of our 742,944 net undeveloped acres, or 0.6%, are scheduled to expire on or before December 31, 2016. An additional 1.6% of our net undeveloped acres are scheduled to expire in 2017 and 0.2% in 2018. If we are unable to renew these leases or any leases scheduled for expiration beyond their expiration date, on favorable terms, we will lose the right to develop the acreage that is covered by an expired lease.

Drilling for and producing natural gas and oil are high-risk activities with many uncertainties.

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

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events and drilling conditions;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- formations with abnormal pressures;
- injury or loss of life and property damage to a well or third-party property;
- leaks or discharges of toxic gases, brine, natural gas, oil, hydraulic fracturing fluid and wastewater from a well;
- environmental accidents, including groundwater contamination;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of natural gas or well fluids.

Any one or more of the factors discussed above could reduce or delay our receipt of drilling and production revenues, thereby reducing our earnings, and could reduce revenues in one or more of our Drilling Partnerships, which may make it more difficult to finance our drilling operations through sponsorship of future partnerships. In addition, any of these events can cause substantial losses, which may not fully be covered by insurance, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties, which could reduce our cash flow and our ability to pay distributions.

Although we maintain insurance against various losses and liabilities arising from our operations, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could reduce our results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would reduce our cash flow from operations and income.

Producing natural gas and oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves. Our ability to find and acquire additional recoverable reserves to replace current and future production at acceptable costs depends on our generating sufficient cash flow from operations and other sources of capital, principally from the sponsorship of new Drilling Partnerships, all of which are subject to the risks discussed elsewhere in this section.

The recent decrease in natural gas and oil prices, or any further decrease in commodity prices, could subject our oil and gas properties to a non-cash impairment loss under U.S. generally accepted accounting principles.

U.S. generally accepted accounting principles require oil and gas properties and other long-lived assets to be reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. We test our oil and gas properties on a field-by-field basis, by determining if the historical cost of proved properties less the applicable depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on our economic interests and our plans to continue to produce and develop proved reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. We estimate prices based on current contracts in place at the impairment testing date, adjusted for basis differentials and market related information, including published future prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates.

Prolonged depressed prices of natural gas and oil may cause the carrying value of our oil and gas properties to exceed the expected future cash flows, and a non-cash impairment loss would be required to be recognized in the financial statements for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. During the year ended December 31, 2015, we recognized $966.6 million of asset impairment primarily related to oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, and unproved acreage in the New Albany Shale, which were impaired due to lower forecasted commodity prices, net of $85.8 million of future hedge gains reclassified from accumulated other comprehensive income.

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

Underground accumulations of natural gas and oil cannot be measured in an exact way. Natural gas and oil reserve engineering requires subjective estimates of underground accumulations of natural gas and oil and assumptions concerning future natural gas prices, production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Our current estimates of our proved reserves are prepared by our internal engineers and our independent petroleum engineers. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates were made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future natural gas prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Our standardized measure is calculated using natural gas prices that do not include financial hedges. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves. We base the estimated discounted future net cash flows from our proved reserves on historical prices and costs. However, actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

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

The timing of both our production and incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Any significant variance in our assumptions could materially affect the quantity and value of reserves, the amount of standardized measure, and our financial condition and results of operations. In addition, our reserves or standardized measure may be revised downward or upward based upon production history, results of future exploitation and development activities, prevailing natural gas and oil prices and other factors. A material decline in prices paid for our production can reduce the estimated volumes of our reserves because the economic life of our wells could end sooner. Similarly, a decline in market prices for natural gas or oil may reduce our standardized measure.

Hedging transactions may limit our potential gains or cause us to lose money.

Pricing for natural gas, NGLs and oil has been volatile and unpredictable for many years. To limit exposure to changing natural gas and oil prices, we may use financial hedges and physical hedges for our production. Physical hedges are not deemed hedges for accounting purposes because they require firm delivery of natural gas and oil and are considered normal sales of natural gas and oil. We general limit these arrangements to smaller quantities than those we project to be available at any delivery point.

In addition, we may enter into financial hedges, which may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties in compliance with the Dodd-Frank Wall Street Reform and Consumer Protection Act. The futures contracts are commitments to purchase or sell natural gas and oil at future dates and generally cover one-month periods for up to six years in the future. The over-the-counter derivative contracts are typically cash settled by determining the difference in financial value between the contract price and settlement price and do not require physical delivery of hydrocarbons.

These hedging arrangements may reduce, but will not eliminate, the potential effects of changing commodity prices on our cash flow from operations for the periods covered by these arrangements. Furthermore, while intended to help reduce the effects of volatile commodity prices, such transactions, depending on the hedging instrument used, may limit our potential gains if commodity prices were to rise substantially over the price established by the hedge. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

In addition, it is not always possible for us to engage in a derivative transaction that completely mitigates our exposure to commodity prices and interest rates. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices and interest rates for which we are unable to enter into a completely effective hedge transaction.

The failure by counterparties to our derivative risk management activities to perform their obligations could have a material adverse effect on our results of operations.

The use of derivative risk management transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. If any of these counterparties were to default on its obligations under our derivative arrangements, such a default could have a material adverse effect on our results of operations, and could result in a larger percentage of our future production being subject to commodity price changes.

Due to the accounting treatment of derivative contracts, increases in prices for natural gas, crude oil and NGLs could result in non-cash balance sheet reductions and non-cash losses in our statement of operations.

We account for our derivative contracts by applying the mark-to-market accounting treatment required for these derivative contracts. We could recognize incremental derivative liabilities between reporting periods resulting from increases or decreases in reference prices for natural gas, crude oil and NGLs, which could result in us recognizing a non-cash loss in our combined statements of operations and a consequent non-cash decrease in our equity between reporting periods. Any such decrease could be substantial. In addition, we may be required to make cash payments upon the termination of any of these derivative contracts.

Regulations adopted by the Commodities Futures Trading Commission could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The ongoing implementation of derivatives legislation adopted by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The Dodd-Frank Act, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation. The CFTC finalized many of the regulations associated with the reform legislation, and is in the process of implementing position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The CFTC recently adopted final rules establishing margin requirements for uncleared swaps entered by swap dealers, major swap participants and financial end users (though non-financial end users are excluded from margin requirements). While, as a non-financial end user, we are not subject to margin requirements, application of these requirements to our counterparties could affect the cost and availability of swaps we use for hedging. The financial reform legislation 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 new legislation and any new regulations could significantly increase the cost of derivative contracts; materially alter the terms of derivative contracts; reduce the availability of derivatives to protect against risks we encounter; reduce our ability to monetize or restructure our derivative contracts in existence at that time; and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation or regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was also 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 legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and/or cash flows.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown environmental or title and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns and increased demand on existing personnel;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and

- the loss of key purchasers of our production; and
- the failure to realize expected growth or profitability.

Our decision to acquire oil and natural gas properties depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations. The scope and cost of the above risks may be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely affect our future growth and the ability to pay distributions.

We may be unsuccessful in integrating the operations from any future acquisitions with our operations and in realizing all of the anticipated benefits of these acquisitions.

The integration of previously independent operations can be a complex, costly and time-consuming process. The difficulties of combining these systems, as well as any operations we may acquire in the future, include, among other things:

- operating a significantly larger combined entity;
- the necessity of coordinating geographically disparate organizations, systems and facilities;
- integrating personnel with diverse business backgrounds and organizational cultures;
- consolidating operational and administrative functions;
- integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;
- the diversion of management's attention from other business concerns;
- customer or key employee loss from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Costs incurred and liabilities assumed in connection with an acquisition and increased capital expenditures and overhead costs incurred to expand our operations could harm our business or future prospects, and result in significant decreases in our gross margin and cash flows.

Our acquisitions may prove to be worth less than we paid, or provide less than anticipated proved reserves, because of uncertainties in evaluating recoverable reserves, well performance, and potential liabilities as well as uncertainties in forecasting oil and natural gas prices and future development, production and marketing costs.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, development potential, well performance, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Our estimates of future reserves and estimates of future production for our acquisitions are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting independent petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain; our proved reserves estimates may thus exceed actual acquired proved reserves. In connection with our assessments, we perform a review of the acquired properties that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of acquired properties are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given the time constraints imposed by the applicable acquisition agreement. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor would it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential.

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

One of our growth strategies is to capitalize on opportunistic acquisitions of natural gas reserves. However, reviews of acquired properties are often incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. A detailed review of records and properties also may not necessarily reveal existing or potential problems, and may not permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Any unidentified problems could result in material liabilities and costs that negatively affect our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable and may be limited by floors and caps on such indemnity.

We may not identify all risks associated with the acquisition of oil and natural gas properties, or existing wells, and any indemnifications we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Our business strategy focuses on acquisitions of undeveloped oil and natural gas properties that we believe are capable of production. We have acquired and may make additional acquisitions of undeveloped oil and gas properties from time to time, subject to available resources. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and other liabilities and other factors. Generally, it is not feasible for us to review in detail every individual property involved in a potential acquisition. In making acquisitions, we generally focus most of our title, environmental and valuation efforts on the properties that we believe to be more significant, or of higher-value. Even a detailed review of properties and records may not reveal all existing or potential problems, nor would it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. In addition, we do not inspect in detail every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we perform a detailed inspection. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable or may be limited by floors and caps, and the financial wherewithal of such seller may significantly limit our ability to recover our costs and expenses. Any limitation on our ability to recover the costs related any potential problem could materially impact our financial condition and results of operations.

Any production associated with the assets acquired in the Rangely Acquisition will decline if the operator’s access to sufficient amounts of carbon dioxide is limited.

Production associated with the assets we acquired in the Rangely Acquisition is dependent on CO_2 tertiary recovery operations in the Rangely Field. The crude oil and NGL production from these tertiary recovery operations depends, in large part, on having access to sufficient amounts of CO_2. The ability to produce oil and NGLs from these assets would be hindered if the supply of CO_2 was limited due to, among other things, problems with the Rangely Field’s current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Any such supply limitation could have a material adverse effect on the results of operations and cash flows associated with these tertiary recovery operations. Our anticipated future crude oil and NGL production from tertiary operations is also dependent on the timing, volumes and location of CO_2 injections and, in particular, on the operator’s ability to increase its combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within the Rangely Field.

Ownership of our oil, gas and natural gas liquids production depends on good title to our property.

Good and clear title to our oil and gas properties is important. Although we will generally conduct title reviews before the purchase of most oil, gas, natural gas liquids and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim, which could result in a reduction or elimination of the revenue received by us from such properties.

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

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

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

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions or by state environmental agencies.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example:

- On December 17, 2014, New York Governor Andrew Cuomo's administration said it would ban hydraulic fracturing for shale gas development throughout the state. Dr. Howard Zucker, the Acting Commissioner of Health, announced that the state Department of Health completed its long-awaited public health review report, which recommended prohibiting hydraulic fracturing in New York. Dr. Zucker cited significant uncertainties regarding risks to public health in concluding that hydraulic fracturing should not proceed in New York until more research is completed. On June 29, 2015 the New York State Department of Environmental Conservation officially prohibited hydraulic fracturing in New York State by issuing its legally-binding Findings Statement. According to the Findings Statement, the Department of Conservation concluded that "there are no feasible or prudent alternatives that would adequately avoid or minimize adverse environmental impacts and that address the scientific uncertainties and risks to public health" associated with hydraulic fracturing.
- Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. On February 14, 2012, legislation was passed in Pennsylvania requiring, among other things, disclosure of chemicals used in hydraulic fracturing. We refer to this legislation as the "2012 Oil and Gas Act." To implement the new legislative requirements, on December 14, 2013 the Pennsylvania Department of Environmental Protection, which we refer to as PADEP, proposed amendments to its environmental regulations at 25 Pa. Code Chapter 78, Subchapter C, pertaining to environmental protection performance standards for surface activities at oil and gas well sites. Pursuant to a legislative bill that passed in July 2014 as a companion to Pennsylvania's budget for 2014 to 2015, PADEP bifurcated its proposed 25 Pa. Code Chapter 78 regulations into two parts. . As proposed, 25 Pa. Code Chapter 78 will apply to conventional wells and 25 Pa. Code Chapter 78A will apply to unconventional wells. On January 6, 2016, PADEP released a final-form rulemaking package of the Chapters 78 and 78a amendments. PADEP identified the key provisions of the final-form rulemaking package to include, but not be limited to, new requirements for operators to address potential impacts to public resources, as well as requirements for operators to identify and monitor abandoned, orphaned and inactive wells prior to hydraulic fracturing. It will also mandate new containment practices and protection water resources, which includes rules for operator response to spill and remediation, and many other changes that will impact our operations. Pennsylvania's Environmental Quality Board is scheduled to meet February 3, 2016 to consider the proposed rulemakings, and PADEP anticipates that the final form rulemaking will likely be finalized in early summer 2016. Additionally, PADEP announced in June 2014 that it also intends to propose amendments to its present environmental regulations at 25 Pa. Code Chapter 78, Subchapters D (relating to well drilling, operation and plugging) and H (relating to underground gas storage). It is anticipated that these proposed amendments will be released in 2016. In January 2015, PADEP issued the results of its Technologically Enhanced Naturally Occurring Radioactive Materials Study, which analyzed levels of radioactivity

associated with oil and gas development in Pennsylvania. Initiated in January 2013, the study evaluated radioactivity levels in flowback waters, treatment solids, and drill cuttings, in addition to the transportation, storage and disposal of these materials. According to the study, PADEP concluded that there is little potential for harm to workers or the public from radiation exposure due to oil and gas development, as well as provided recommendations for further study to be conducted.

- Ohio has in recent years expanded its oil and gas regulatory program. In June 2012, Ohio passed legislation that made several significant amendments to the state's oil and gas laws, including additional permitting requirements, chemical disclosure requirements, and site investigation requirements for horizontal wells. In June 2013, legislation was adopted imposing sampling requirements and disposal restrictions on certain drilling wastes containing naturally occurring radioactive material and requiring the state regulatory authority to adopt rules on the design and operation of facilities that store, recycle, or dispose of brine or other oil and natural gas related waste materials. In July 2015, the regulatory authority adopted rules imposing detailed construction standards on well pads, and in April 2014, Ohio announced new standard drilling permit conditions to address concerns regarding seismic activity in certain parts of the state.
- For wells spudded January 1, 2014 and after, the Texas Railroad Commission adopted new rules regarding well casing, cementing, drilling, completion and well control for ensuring hydraulic fracturing operations do not contaminate nearby water resources. Recent Railroad Commission rules and regulations focus on prevention of waste, as evidenced by regulations relating to the commercial recycling of produced water and/or hydraulic fracturing flowback fluid approved in September 2012, and more stringent permitting for venting/flaring of casinghead gas and gas well gas beginning in January 2014.
- A West Virginia rule that became effective July 1, 2013 imposes more stringent regulation of horizontal drilling and was promulgated to provide further direction in the implementation and administration of the Natural Gas Horizontal Well Control Act that became effective on December 14, 2011. In 2014, West Virginia revised its solid waste regulations to allow landfills to increase their tonnage limits specifically for natural gas drilling wastes, along with requiring more stringent controls and radiation testing of landfills located in the state.

In addition to state law, local land use restrictions, such as municipal ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. Recent changes regarding local land use restrictions in Pennsylvania occurred because of decisions of the Pennsylvania Supreme and Commonwealth Courts. On December 19, 2013, when the Pennsylvania Supreme Court issued its Robinson Township v. Commonwealth of Pennsylvania ruling, which invalidated key sections of the 2012 Oil and Gas Act that placed limits on the regulatory authority of local governments. Additionally, the Pennsylvania Supreme Court remanded a number of issues to the Commonwealth Court for further decision. On July 17, 2014, the Commonwealth Court ruled on the remanded issues. The cumulative effect of the Supreme and Commonwealth Court rulings is that all of the challenged provisions relating to local ordinances contained in the 2012 Oil and Gas Act are invalid, except for the definitions section and most of the updated preemption language in the 2012 Oil and Gas Act that was included from the previous 1984 Oil and Gas Act. The total impact of these rulings in Robinson Township, which is ongoing before the Supreme Court, are not clear and will occur over an extended period of time. An immediate impact of the rulings has been increased regulatory impediments and disputes at the local government level, as well as validity challenges initiated by private landowners alleging that local ordinances do not adequately protect health, safety, and welfare. Additionally, there is a pending challenge by an industry association regarding the Robinson Township decision and PADEP's use of its Public Resources Form and Pennsylvania Natural Diversity Index Policy based on a provision of the 2012 Oil and Gas Act (58 C.S. § 3215(c)). The petitioner is seeking a declaration from the Supreme Court that PADEP is enjoined from application and enforcement of that provision pursuant to the Court's Robinson Township ruling.

On June 30, 2014, the New York Court of Appeals issued its opinion in Wallach v. Town of Dryden affirming local zoning laws adopted by two upstate municipalities that prohibited oil and gas-related activities within their borders. Specifically, the Court of Appeals ruled that there was nothing within the plain language, statutory scheme and legislative history of the New York Oil, Gas and Solution Mining Law that manifested an intent by the legislature to preempt a municipality's home rule authority to regulate land use. On October 16, 2014, the New York Court of Appeals denied a request by the petitioner – the bankruptcy trustee for Norse Energy – to re-hear arguments in the case. If state, local or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. Generally, Federal, state and local restrictions and requirements are applied consistently to similar types of producers (e.g., conventional, unconventional, etc.), regardless of size of the producing company.

Although, to date, the hydraulic fracturing process has not generally been subject to regulation at the federal level, there are certain governmental reviews either under way or being proposed that focus on environmental aspects of hydraulic fracturing practices, and some federal regulation has taken place. A few of these initiatives are listed here, although others may exist now or be implemented in the future. In April 2012, President Obama established an Interagency Working Group to Support Safe and Responsible Development of Unconventional Domestic Natural Gas Resources with the purpose of coordinating the policies and activities of agencies regarding unconventional gas development. The United States Environmental Protection Agency (the "EPA") has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel as an additive under the Safe Drinking Water Act. In May 2012, the EPA issued draft permitting guidance for oil and gas hydraulic fracturing activities using diesel fuel. In February 2014, the EPA released its revised final guidance document on Safe Drinking Water Act underground injection control permitting for hydraulic fracturing using diesel fuels, along with responses to selected substantive public comments on the

EPA's previous draft guidance, a fact sheet and a memorandum to the EPA's regional offices regarding implementation of the guidance. The process for implementing the EPA's final guidance document may vary across the states depending on the regulatory authority responsible for implementing the Safe Drinking Water Act underground injection control program in each state. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, the EPA is currently studying the potential impacts of hydraulic fracturing on drinking water and groundwater, and, in fact, released a Draft Assessment on June 4, 2015.

In 2013, the EPA indicated that it intended to propose a draft water quality criteria document that would update the aquatic life water quality criteria for chloride by the summer of 2014. However, the EPA has yet to propose the draft water quality criteria document and it has not provided an updated timeframe for the proposal. On April 7, 2015, the EPA published its "Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Point Source Category" in the Federal Register, and accepted comments through July 17, 2015. As proposed, the regulations would establish pretreatment standards for discharges of wastewater pollutants from onshore unconventional oil and gas extractive facilities to publicly-owned treatment works. The EPA has proposed pretreatment standards for existing and new sources that would prohibit the indirect discharge of wastewater pollutants associated with onshore unconventional gas extraction facilities. Additionally, the EPA published its "Final 2014 Effluent Guidelines Program Plan" on August 4, 2015 and confirmed its schedule for the aforementioned ongoing unconventional oil and gas extraction effluent guideline rulemaking, as well as announced a final decision to continue its detailed study to investigate centralized waste treatment facilities that accept oil and gas extraction wastewaters. On May 11, 2012, the U.S. Department of the Interior, Bureau of Land Management published a proposed rule that includes provisions requiring disclosure of chemicals used in hydraulic fracturing and construction standards for hydraulic fracturing on federal and Indian lands. On May 24, 2013, the Bureau of Land Management published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands. On March 26, 2015, BLM issued a final rule updating the regulations governing hydraulic fracturing on federal and Indian lands that was set to go into effect on June 24, 2015. Subsequently on June 23, 2015 in a lawsuit filed by several states and industry associations before the U.S. District Court for the District of Wyoming (State of Wyoming v. Dep't of Interior, No. 2:15-cv-00043), a stay of the effective date of the BLM's pending rule was lodged. The petitioners specifically requested that Court grant a preliminary injunction of the final rule and, on September 30, 2015, the U.S. District Court granted the preliminary injunction thereby enjoining the final rule.

Certain members of the U.S. Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, and Congress has asked the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing. In addition, Congress requested the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. On December 16, 2013, the U.S. Energy Information Administration published an abridged version of its Annual Energy Outlook 2014 with projections to 2040 report, with the full report released on May 7, 2014. A subsequent Annual Energy Outlook 2015 was released on April 14, 2015, with the next coming June 2016. These ongoing proposed studies, depending on their degree of pursuit and any meaningful results obtained, could result in initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or one or more other regulatory mechanisms. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform hydraulic fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could be significantly affected.

Some of the potential effects of changes in Federal, state or local regulation of hydraulic fracturing operations could include the following:

- additional permitting requirements and permitting delays;
- increased costs;
- changes in the way operations, drilling and/or completion must be conducted;
- increased recordkeeping and reporting; and
- restrictions on the types of additives that can be used.

Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of greenhouse gas emissions. Facilities required to obtain Prevention of Significant Deterioration permits because of their potential criteria pollutant emissions may be required to comply with "best available control technology" standards for greenhouse gases. These regulations could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

While Congress has from time to time considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs that typically require major sources of greenhouse gas emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those greenhouse gases. In addition, the Obama Administration announced its Climate Action Plan in 2013, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas industry. The Obama Administration announced a formal methane reduction strategy in January 2015, and is taking actions to implement the strategy (see "Item 1. Business- Environmental Matters and Regulation - Greenhouse Gas Regulation and Climate Change"). Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations.

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

Rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

In 2012, the EPA established the NSPS rule for oil and natural gas production, transmission, and distribution, and also made significant revisions to the existing National Emission Standards for Hazardous Air Pollutants ("NESHAP") rules for oil and natural gas production, transmission, and storage facilities. These rules require oil and natural gas production facilities to conduct "green completions" for hydraulic fracturing, which is recovering rather than venting the gas and natural gas liquids that come to the surface during completion of the fracturing process. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. Both the NSPS and NESHAP rules continue to evolve based on new information and changing environmental concerns. The NSPS rule was most recently revised in August 2015, 80 Fed. Reg. 48262 (Aug. 12, 2015), and it will be revised again when the EPA finalizes the rulemaking to implement the national methane reduction strategy (see "Item 1. Business- Environmental Matters and Regulation - Greenhouse Gas Regulation and Climate Change"). In November 2015, the EPA issued a formal request for data and information which suggests that the agency may revise the NESHAP rules in the near future. In addition to these EPA rules, BLM released a proposed rule in January 2016 to reduce oil and gas industry emissions and minimize waste of produced gas from Federal and Indian leases.

States are also proposing increasingly stringent requirements for air pollution control and permitting for well sites and compressor stations. For example, in January 2016, the Governor of Pennsylvania announced a comprehensive new regulatory strategy for reducing methane emissions from new and existing oil and natural gas operations, including well sites, compressor stations, and pipelines. Implementation of this strategy will result in significant changes to the air permitting and pollution control standards that apply to the oil and gas industry in Pennsylvania. It may also influence air programs in other oil and gas-producing states. Moreover West Virginia issued General Permit 70-A for natural gas production facilities at the well site in 2013. In response to industry concerns regarding the restrictiveness of the general permit, in November 2015, West Virginia issued General Permit 70-B which provides more flexibility for emission sources located at the well site.

Overall, compliance with new rules regulating air emissions from our operations could result in significant costs, including increased capital expenditures and operating costs, and could affect the results of our business.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulation. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition, results of operations and our ability to make distributions to our unitholders.

Our drilling and production operations require adequate sources of water to facilitate the fracturing process and the disposal of flowback and produced water. If we are unable to dispose of the flowback and produced water from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas economically and in commercial quantities could be impaired.

A significant portion of our natural gas extraction activity utilizes hydraulic fracturing, which results in water that must be treated and disposed of in accordance with applicable regulatory requirements. Environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance. For example, Pennsylvania’s 2012 Oil and Gas Act requires the development, submission and approval of a water management plan before withdrawing or using water from water sources in Pennsylvania to drill or hydraulically fracture an unconventional well. The requirements of these plans continue to be modified by proposed amendments to state regulations and agency policies and guidance. For Pennsylvania operations located in the Susquehanna River Basin, the Susquehanna River Basin Commission regulates consumptive water uses, water withdrawals, and the diversions of water into and out of the Susquehanna River Basin, and specific approvals are required prior to initiating drilling activities. In June 2012, Ohio passed legislation that established a water withdrawal and consumptive use permit program in the Lake Erie watershed. If certain withdrawal thresholds are triggered due to water needs for a particular project, we will be required to develop a Water Conservation Plan and obtain a withdrawal permit for that project. West Virginia also requires that if a certain amount of water is withdrawn water management plans are required and/or registration and reporting requirements are triggered.

Our ability to collect and dispose of flowback and produced water will affect our production, and potential increases in the cost of wastewater treatment and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of wastewater, drilling fluids and other substances associated with the exploration, development and production of gas and oil. For example, in July 2012, the Ohio Department of Natural Resources promulgated amendments to the regulations governing disposal wells in Ohio. The rules provide the Department of Natural Resources with the authority to require certain testing as part of the process for obtaining a permit for the underground injection of produced water, and require all new disposal wells to be equipped with continuous pressure monitors and automatic shut off devices.

Impact fees and severance taxes could materially increase our liabilities.

In an effort to offset budget deficits and fund state programs, many states have imposed impact fees and/or severance taxes on the natural gas industry. In February 2012, the Commonwealth of Pennsylvania enacted an “impact fee” on unconventional natural gas and oil production which includes the Marcellus Shale. The impact fee is based upon the year a well is spudded and varies, like most severance taxes, based upon natural gas prices. For the year ended December 31, 2015, we estimated that the impact fee for our wells, including the wells in our Drilling Partnerships will approximately $643,000. This is compared to an impact fee of approximately $1.0 million for the year ended December 31, 2014, an impact fee of approximately $1.7 million for the year ended December 2013 and an impact fee of approximately $2.0 for year ended December 31, 2012.

Because we handle natural gas, natural gas liquids and oil, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of substances into the environment.

How we plan, design, drill, install, operate and abandon natural gas wells and associated facilities are matters subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

- The federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;
- The federal Clean Water Act and comparable state laws and regulations that impose obligations related to spills, releases, streams, wetlands and discharges of pollutants into regulated bodies of water;

- The federal Resource Conservation and Recovery Act (“RCRA”) and comparable state laws that impose requirements for the handling and disposal of waste, including produced waters, from our facilities;
- The federal Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”) and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal; and
- Wildlife protection laws and regulations such as the Migratory Bird Treaty Act that requires operators to cover reserve pits during the cleanup phase of the pit, if the pit is open more than 90 days.

Complying with these requirements is expected to increase costs and prompt delays in natural gas production. There can be no assurance that we will be able to obtain all necessary permits and, if obtained, that the costs associated with obtaining such permits will not exceed those that previously had been estimated. It is possible that the costs and delays associated with compliance with such requirements could cause us to delay or abandon the further development of certain properties.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. These enforcement actions may be handled by the EPA and/or the appropriate state agency. In some cases, the EPA has taken a heightened role in enforcement activities targeting the oil and gas extraction sector. For example, in 2011, the EPA Region III requested the lead on all oil and gas related violations in the United States Army Corps of Engineers’ Pittsburgh District. The EPA, the United States Army Corps of Engineers’ and the United States Department of Justice have been actively pursuing instances of unpermitted stream and wetland impacts, particularly for activities occurring in West Virginia. We also understand that the EPA has taken an increased interest in assessing operator compliance with the Spill Prevention, Control and Countermeasures regulations, set forth at 40 CFR Part 112.

Certain environmental statutes, including RCRA, CERCLA, the federal Oil Pollution Act and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where certain substances have been disposed of or otherwise released, whether caused by our operations, the past operations of our predecessors or third parties. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. For example, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies may be enacted or adopted and could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover remediation costs under our respective insurance policies.

We are subject to comprehensive federal, state, local and other laws and regulations that could increase the cost and alter the manner or feasibility of us doing business.

Our operations are regulated extensively at the federal, state and local levels. The regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities will be subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas and oil we may produce and sell. A major risk inherent in a drilling plan is the need to obtain drilling permits from state agencies and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could inhibit our ability to develop our respective properties. The natural gas and oil regulatory environment could also change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, reduce our profitability. For example, Pennsylvania's 2012 Oil and Gas Act imposes significant, costly requirements on the natural gas industry, including the imposition of increased bonding requirements and impact fees for unconventional gas wells, based on the price of natural gas and the age of the unconventional gas well. PADEP's proposed regulatory amendments associated with this legislation, when finalized will affect how natural gas operations are conducted in Pennsylvania. Moreover, PADEP has indicated that more regulatory amendments are likely to be proposed in 2016. West Virginia has promulgated regulations associated with its existing Horizontal Well Control Act and has developed new aboveground storage tank laws that are being applied broadly and impose stringent requirements that affect the natural gas industry. We may be put at a competitive disadvantage to larger companies in the industry that can spread these additional costs over a greater number of wells and these increased regulatory hurdles over a larger operating staff.

We may not be able to continue to raise funds through our Drilling Partnerships at desired levels, which may in turn restrict our ability to maintain our drilling activity at recent levels.

We sponsor limited and general partnerships to finance certain of our development drilling activities. Accordingly, the amount of development activities that we will undertake depends in large part upon our ability to obtain investor subscriptions to invest in these partnerships. We raised $59.3 million, $166.8 million and $150.0 million in 2015, 2014, and 2013, respectively. In the future, we may not be successful in raising funds through these Drilling Partnerships at the same levels that it experienced, and we also may not be successful in increasing the amount of funds we raise. Our ability to raise funds through our Drilling Partnerships depends in large part upon the perception of investors of their potential return on their investment and their tax benefits from investing in them, which perception is influenced significantly by our historical track record of generating returns and tax benefits to the investors in our existing partnerships.

In the event that our Drilling Partnerships do not achieve satisfactory returns on investment or the anticipated tax benefits, we may have difficulty in maintaining or increasing the level of Drilling Partnership fundraising relative to the levels achieved by us. In this event, we may need to seek financing for our drilling activities through alternative methods, which may not be available, or which may be available only on a less attractive basis than the financing we realized through these Drilling Partnerships, or we may determine to reduce drilling activity.

Changes in tax laws may impair our ability to obtain capital funds through Drilling Partnerships.

Under current federal tax laws, there are tax benefits to investing in Drilling Partnerships, including deductions for intangible drilling costs and depletion deductions. However, both the Obama Administration's budget proposal for fiscal year 2017 and other recently introduced legislation include proposals that would, among other things, eliminate or reduce certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs and certain environmental clean-up costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. The repeal of these oil and gas tax benefits, if it happens, would result in a substantial decrease in tax benefits associated with an investment in our Drilling Partnerships. These or other changes to federal tax law may make investment in the Drilling Partnerships less attractive and, thus, reduce our ability to obtain funding from this significant source of capital funds.

Fee-based revenues may decline if we are unsuccessful in sponsoring new Drilling Partnerships.

Our fee-based revenues will be based on the number of Drilling Partnerships we sponsor and the number of partnerships and wells we manage or operate. If we are unsuccessful in sponsoring future Drilling Partnerships, our fee-based revenues may decline.

Our revenues may decrease if investors in our Drilling Partnerships do not receive a minimum return.

We have agreed to subordinate a portion of our share of production revenues, net of corresponding production costs, to specified returns to the investor partners in the Drilling Partnerships, typically 10% to 12% per year for the first five to eight years of distributions. Thus, our revenues from a particular partnership will decrease if we do not achieve the specified minimum return. For the year ended December 31, 2015, $1.7 million of our revenues, net of corresponding production costs, were subordinated, which reduced our cash distributions received from the Drilling Partnerships. For the year ended December 31, 2014, the subordinated amount, net of corresponding production costs, was $5.3 million and for the year ended December 31, 2013, it was $9.6 million.

We or one of our subsidiaries may be exposed to financial and other liabilities as the managing general partner in Drilling Partnerships.

We or one of our subsidiaries serves as the managing general partner of the Drilling Partnerships and will be the managing general partner of new Drilling Partnerships that we sponsor. As a general partner, we or one of our subsidiaries will be contingently liable for the obligations of the partnerships to the extent that partnership assets or insurance proceeds are insufficient. We have agreed to indemnify each investor partner in the Drilling Partnerships from any liability that exceeds such partner’s share of the Drilling Partnership’s assets.

Our historical financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

Some of the historical financial information that we have included in this report may not necessarily reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. The general and administrative expenses reflected in the financial statements for Atlas Energy E&P Operations include an allocation for certain corporate functions historically provided by Atlas Energy, Inc. These allocations were based on what we and Atlas Energy, Inc. considered to be reasonable reflections of the historical utilization levels of these services required in support of the business. We have not adjusted the historical financial statements for Atlas Energy E&P Operations to reflect changes that occurred in our cost structure and operations as a result of our transition to becoming a stand-alone public company. Therefore, the financial statements of Atlas E&P Operations and our historical financial information may not necessarily be indicative of what our financial position, results of operations or cash flows will be in the future.

A cyber incident or a terrorist attacks could result in information theft, data corruption, operational disruption and/or financial loss.

We have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future cyber or terrorist attacks than other targets in the United States. Deliberate attacks on, or security breaches in our systems or infrastructure, or the systems or infrastructure of third parties or the cloud, could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, challenges in maintaining our books and records and other operational disruptions and third party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Risks Relating to the Ownership of Our Units

If prices of our common and/or preferred units decline, our unitholders could lose a significant part of their investment.

The market price of our units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in securities analysts' recommendations and their estimates of our financial performance;
- the public's reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of natural gas and oil companies and securities of publicly traded limited partnerships and limited liability companies;
- fluctuations in natural gas and oil prices;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other natural gas and oil companies;
- variations in the amount of our cash distributions;

- future issuances and sales of our units; and
- changes in general conditions in the U.S. economy, financial markets or the natural gas and oil industry.

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

Sales of our units may cause our unit price to decline.

Sales of substantial amounts of our units in the public market, or the perception that these sales may occur, could cause the market price of our units to decline. In addition, the sale of these units could impair our ability to raise capital through the sale of additional units.

At December 31, 2015, Atlas Energy Group, our general partner, owned approximately 20.96 million common and 3.75 million preferred limited partner units, representing an approximately 23.3% limited partner ownership interest in us. Our general partner is free to sell some or all of these common units at any time. In addition, we have agreed to register under the U.S. Securities Act of 1933, as amended, which we refer to as the Securities Act, any sale of common units held by our general partner and its affiliates. These registration rights allow our general partner and its affiliates to request registration of their common units and to include any of those units in a registration of other securities by us. If our general partner and its affiliates were to sell a substantial portion of their units, it could reduce the market price of our outstanding common units. Additionally, unless previously converted, all of our Class C preferred units, including all of our general partner's preferred units, will convert into common units on a one-for-one basis on July 31, 2016. At December 31, 2015, there were 3,749,986 Class C preferred units outstanding.

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

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

We may not have sufficient cash flow from operations to pay the minimum quarterly distribution following the establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient cash flow from operations each quarter to pay the minimum quarterly distribution. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserve amounts that our general partner establishes to provide for the conduct of our business, including operations, future capital expenditures and our anticipated future credit needs, future debt service requirements and future cash distributions to our unitholders and the holders of the distribution incentive rights. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas and oil we produce;
- the price at which we sell our natural gas and oil;
- the level of our operating costs;
- our ability to acquire, locate and produce new reserves;
- the results of our hedging activities;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable on it; and
- the level of our capital expenditures.

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

- our ability to make working capital borrowings to pay distributions;
- the cost of acquisitions, if any;
- fluctuations in our working capital needs;
- timing and collectability of receivables;
- restrictions on distributions imposed by lenders;
- payments to our general partner; and
- the strength of financial markets and our ability to access capital or borrow funds.

The amount of cash we have available for distribution to unitholders, if any, depends primarily on our cash flow and not solely on profitability.

The amount of cash that we have available for distribution, if any, depends primarily on our cash flow, including cash reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses, and we may not make cash distributions during periods when we record net income.

We have the right to borrow to make distributions. Repayment of these borrowings will decrease cash available for future distributions, and covenants in our debt documents have restrictions and financial covenants that may restrict our ability to pay distributions to our unitholders.

Our partnership agreement allows us to borrow to make distributions. We may make short term borrowings under our credit facility, which we refer to as working capital borrowings, to make distributions. The primary purpose of these borrowings would be to mitigate the effects of short term fluctuations in our working capital that would otherwise cause volatility in our quarter to quarter distributions.

Our credit facilities and the indentures governing our senior notes contain various restrictive covenants that limit our ability to, among other things, pay distributions or redeem or repurchase our securities. In addition, our debt documents require us to maintain specified financial ratios. Our ability to meet those financial ratios can be affected by events beyond our control, and we may be unable to meet those tests. These restrictions and financial covenants may restrict our ability to pay distributions to our unitholders.

Cost reimbursements due to our general partner for services provided may be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to our partnership agreement, our general partner receives reimbursement for the provision of various general and administrative services for our benefit. Payments for these services may be substantial, are not subject to any aggregate limit, and will reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

If we do not pay distributions on our preferred units in any fiscal quarter, we will be unable to pay distributions on our common units until all unpaid preferred unit distributions have been paid, and our common unitholders are not entitled to receive distributions for such prior periods.

If we do not pay the required distributions on our preferred units, we will be unable to pay distributions on our common units. Additionally, because distributions to our preferred unitholders are cumulative, we will have to pay all unpaid accumulated preferred distributions before we can pay any distributions to our common unitholders. Also, because distributions to our common unitholders are not cumulative, if we do not pay distributions on our common units with respect to any quarter, our common unitholders will not be entitled to receive distributions covering any prior periods.

With limited exceptions, our partnership agreement restricts the voting rights of unitholders that own 20% or more of our common units.

Our partnership agreement prohibits any person or group that owns 20% or more of our common units then outstanding, other than our general partner, its affiliates and transferees, from voting on any matter.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts committee of its board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner, as the initial holder of our incentive distribution rights, has the right, at any time when it has received incentive distributions at the highest level to which it is entitled (50.0%) for each of the prior four consecutive fiscal quarters and the amount of each such distribution did not exceed adjusted operating surplus for such quarter, to reset the initial target distribution levels at higher levels based on our cash distributions at the time of the exercise of the reset election. Following any reset election, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. If our general partner transfers all or a portion of our incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this reset right.

If a reset election is made, then the holder of the incentive distribution rights will be entitled to receive additional common units from the partnership equal to the number of common units that would have entitled the holder of such additional common units to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the incentive distribution rights in the prior two quarters. We anticipate that the holder of our incentive distribution rights may exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such reset. It is possible, however, that the reset right is exercised at a time when the holder is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels.

Our unitholders who fail to furnish certain information requested by our general partner or who our general partner determines are not eligible citizens may not be entitled to receive distributions in kind upon our liquidation and their units will be subject to redemption.

We have the right to redeem all of the units of any holder that is not an eligible citizen if we are or become subject to federal, state, or local laws or regulations that, in the determination of our general partner, create a substantial risk of cancellation or forfeiture of any property in which we have an interest because of the nationality, citizenship or other related status of any limited partner. Our general partner may require any limited partner or transferee to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within a reasonable period after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, the limited partner may be treated as a non-citizen assignee. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation. Furthermore, we have the right to redeem all of the units of any holder that is not an eligible citizen or fails to furnish the requested information.

Units held by persons who are non-taxpaying assignees will be subject to the possibility of redemption.

If our general partner determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on our ability to operate our assets or generate revenues from our assets, then our general partner may adopt such amendments to our partnership agreement as it determines are necessary or appropriate to obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant) and permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rate that can be charged to customers by our subsidiaries or who fails to comply with the procedures instituted by our general partner to obtain proof of the U.S. federal income tax status.

Holders of our units have limited voting rights and are not entitled to elect our general partner or its board of directors.

Unlike the holders of common stock in a corporation, our common unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Common unitholders do not elect our general partner or the members of its board of directors on an annual or other continuing basis. The board of directors of our general partner is elected by its unitholders. Furthermore, the vote of the holders of at least two-thirds of all outstanding common units is required to remove our general partner. As a result of these limitations on the ability of holders of our common units to influence the management of our company, the price at which the common units trade could be diminished.

Additionally, holders of the preferred units have no voting rights with respect to matters that generally require the approval of voting unitholders. Voting rights for holders of preferred units exist primarily with respect to voting on amendments to our certificate of formation and partnership agreement that materially and adversely affect the rights of the holders of preferred units or authorizing, increasing or creating additional classes or series of our units that are senior to the preferred units.

Our general partner’s interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of our unitholders, either before March 13, 2022 in a merger or in a sale of all or substantially all of its assets, or after March 13, 2022 under any circumstances if such transfer is otherwise in compliance with our partnership agreement. In addition, our general partner may transfer all or a portion of its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase distributions to unitholders over time as it would if it had retained ownership of the incentive distribution rights.

We may issue an unlimited number of additional units, including units that are senior to the common units and parri passu with the preferred units, without unitholder approval, which would dilute unitholders’ ownership interests. Any additional issuance will not dilute the general partner interest in us.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting, including additional preferred units and any securities parity with the preferred units without any vote of the holders of the preferred units (except where the cumulative distributions on the preferred units or any parity securities are in arrears) and without the approval of our common unitholders. The issuance by us of additional units or other equity interests of equal or senior rank will have the following effects:

- our unitholders’ proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units and preferred units may decline.

Moreover, the issuance of additional common units will not dilute the holder of our class A units. The class A units represent a 2% general partner interest in us, and the holder of such class A units will be entitled to 2% of our cash distributions without any obligation to make future capital contributions to us. The 2% sharing ratio of the class A units will not be reduced if we issue additional common units in the future. Because the 2% sharing ratio will not be reduced if we issue additional common units, and in order to ensure that each class A unit represents the same percentage economic interest in us as one common unit, if we issue additional common units, we will also issue to our general partner, for no additional consideration and without any requirement to make a capital contribution, an additional number of class A units so that the total number of outstanding class A units after such issuance equals 2% of the sum of the total number of common units and class A units after such issuance.

In addition, the payment of distributions on any additional units may increase the risk that we will not be able to make distributions at our prior per unit distribution levels. To the extent new units are senior to our common units, their issuance will increase the uncertainty of the payment of distributions on our common units.

As a limited partnership, we qualify for, and rely on, exemptions from certain corporate governance requirements of the NYSE rules.

Under the NYSE listing standards, a limited partnership is exempt from certain NYSE corporate governance requirements, including:

- the requirement that a majority of the board of directors consists of independent directors;
- the requirement that we have a nominating/governance committee that is comprised entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;

- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- the requirement for an annual performance evaluation of the nominating/governance and compensation committees.

We utilize some of the foregoing exemptions from the corporate governance requirements of the NYSE listing standards. As a result, we do not have a nominating/governance committee or a compensation committee.

In addition, NYSE rules requiring that stockholder approval be obtained prior to certain issuances of equity securities do not apply to limited partnerships.

Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

Our units may be delisted from the New York Stock Exchange.

On January 12, 2016, we were notified by the NYSE that we are not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of our common units had been less than $1.00 for 30 consecutive trading days. We are required to remedy this in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE, and, if we are unable to do so, our preferred units that are currently listed on the NYSE and our common units may be delisted by the NYSE. If delisting occurs, it could be more difficult to buy or sell our units and the price of our units could decline. Delisting could also affect our ability to raise capital. If we were delisted from the NYSE, we could seek to move trading of the units to the NYSE MKT exchange or OTC. These methods of trading could significantly impair our ability to raise new capital.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than two-thirds of the outstanding class of any limited partner interests, our general partner will have the right, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of such class of limited partner interests held by unaffiliated persons at a price equal to the greater of (1) the highest cash price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and (2) the average of the daily closing prices of the limited partner interests of such class over the 20 trading days preceding the date three days before the date of the mailing of the exercise notice for such call right. You may be required to sell your units at an undesirable time or price. You may also incur a tax liability upon a sale of your units.

The credit and risk profiles of our general partner could adversely affect our credit ratings and profile.

The credit and risk profiles of our general partner may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our general partner over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our general partner, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness.

Unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Unitholders could be liable for any and all of our obligations as if they were a general partner if, among other potential reasons:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- unitholders' right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them, or other liabilities with respect to ownership of our units.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them.
Under Section 17–607 of the Delaware Revised Uniform Limited Partnership Act ("Delaware Act"), we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement.

The preferred units represent perpetual equity interests in us.

The preferred units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As a result, holders of the preferred units may be required to bear the financial risks of an investment in the preferred units for an indefinite period of time. In addition, the preferred units rank junior to all our current and future indebtedness (including indebtedness outstanding under our revolving credit facility, our second lien term loan facility and our senior notes), and any other senior securities we may issue in the future with respect to assets available to satisfy claims against us.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for U.S. federal income tax purposes or we were to become subject to a material amount of entity-level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available for distribution.

The anticipated after-tax benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter that affects us.

We are currently treated as a partnership for federal income tax purposes, which requires that 90% or more of our gross income for every taxable year consist of qualifying income, as defined in Section 7704 of the Internal Revenue Code. Qualifying income is defined as income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy and timber). We may not meet this requirement or current law may change so as to cause, in either event, us to be treated as a corporation for federal income tax purposes or otherwise be subject to federal income tax. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

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

53

Current law or our business may change so as to cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. Our limited partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local or foreign income tax purposes, the minimum quarterly distribution amount and the incentive distribution amounts will be adjusted to reflect the impact of that law on us.

Unitholders are required to pay taxes on their share of our taxable income, including their share of ordinary income and capital gain upon dispositions of properties by us or cancellation of debt, even if they do not receive any cash distributions from us. A unitholder’s share of our taxable income, gain, loss and deduction, or specific items thereof, may be substantially different than the unitholder’s interest in our economic profits.

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

For example, we have repurchased approximately $20.3 million of our 7.75% Senior Notes and approximately $12.1 million of our 9.25% Senior Notes at prices lower than face amount (See “Subsequent Events”). These repurchases will, and other similar transactions in the future may, result in cancellation of debt income that will be allocated to our unitholders. Some or all of our unitholders may be allocated substantial amounts of such taxable income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect to each unitholder would depend on the unitholder's individual tax position with respect to the units; however, taxable income allocations from us, including cancelation of debt income, increase a unitholder’s tax basis in their units.

In addition, we may sell a portion of our properties and use the proceeds to pay down debt or acquire other properties rather than distributing the proceeds to our unitholders, and some or all of our unitholders may be allocated substantial taxable income with respect to that sale. A unitholder’s share of our taxable income upon a disposition of property by us may be ordinary income or capital gain or some combination thereof. Even where we dispose of properties that are capital assets, what otherwise would be capital gains may be recharacterized as ordinary income in order to “recapture” ordinary deductions that were previously allocated to that unitholder related to the same property.

A unitholder’s share of our taxable income and gain (or specific items thereof) may be substantially greater than, or our tax losses and deductions (or specific items thereof) may be substantially less than, the unitholder’s interest in our economic profits. This may occur, for example, in the case of a unitholder who purchases units at a time when the value of our units or of one or more of our properties is relatively low or a unitholder who acquires units directly from us in exchange for property whose fair market value exceeds its tax basis at the time of the exchange. Cash distributions from us decrease a unitholder’s tax basis in its units, and the amount, if any, of excess distributions over a unitholder’s tax basis in its units will, in effect, become taxable income to the unitholder, above and beyond the unitholder’s share of our taxable income and gain (or specific items thereof).

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

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (“IRAs”) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

A successful IRS contest of the U.S. federal income tax positions we take may harm the market for our common units, and the costs of any contest will reduce cash available for distribution.

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

We treat each holder of our common units as having the same tax benefits without regard to the common units held. The IRS may challenge this treatment, which could reduce the value of the common units.

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

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

If a unitholder sells their common units, they will recognize a gain or loss equal to the difference between the amount realized and the adjusted tax basis in those common units. Prior distributions and the allocation of losses, including depreciation deductions, to the unitholder in excess of the total net taxable income allocated to them, which decreased the tax basis in their common units, will, in effect, become taxable income to them if the common units are sold at a price greater than their tax basis in those common units, even if the price is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder.

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a 12-month period.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A constructive termination results in the closing of our taxable year for all unitholders and in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns, and unitholders receiving two Schedule K-1s, for one fiscal year and the cost of the preparation of these returns will be borne by all unitholders.

Unitholders may be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We do business and own assets in Alabama, Colorado, Indiana, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia and West Virginia. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all U.S. federal, foreign, state and local tax returns that may be required of such unitholder.

The IRS may challenge our tax treatment related to transfers of units, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. If the IRS were to challenge this method or new U.S. Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between us and our public unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of our unitholders and our general partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of our common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain on the sale of common units by our unitholders and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of our unitholders without the benefit of additional deductions.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Treatment of distributions on our preferred units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our preferred units than the holders of our common units.

The tax treatment of distributions on our preferred units is uncertain. We will treat the holders of preferred units as partners for tax purposes and will treat distributions on the preferred units as guaranteed payments for the use of capital that will generally be taxable to the holders of preferred units as ordinary income. Although a holder of preferred units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions quarterly. Otherwise, the holders of Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction. Nor will we allocate any share of our nonrecourse liabilities to the holders of preferred units. If the preferred units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of preferred units.

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

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we will have the ability to elect to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that we will choose to make such election or that such election will be effective in all circumstances. If we are unable to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, or we choose not to do so, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable to us for tax years beginning on or prior to December 31, 2017.

Risks Relating to Our Ongoing Relationship with Our General Partner and its Affiliates

Our general partner, through its subsidiary, owns our own common and preferred limited partner units representing an approximate 23.3% limited partner ownership interest. Therefore, our general partner possesses significant influence on all matters submitted to a vote of our unitholders.

At December 31, 2015, a wholly-owned subsidiary of Atlas Energy Group owned approximately 20.96 million common and 3.75 million preferred limited partner units, representing an approximate 23.3% limited partner ownership interest in us. Accordingly, our general partner possesses significant influence over matters submitted to our unitholders for approval, and could exercise such influence in a manner that is not in the best interests of our other unitholders, including the ability to effectively prevent the approval of certain matters, such as removal of our general partner and other extraordinary transactions for which super-majority approval is required under applicable Delaware law. In addition, our general partner is able to control, subject to our partnership agreement and applicable law, all matters affecting us, including:

- any determination with respect to our business direction and policies, including the appointment and removal of officers;
- any determinations with respect to mergers, business combinations or disposition of assets;
- our financing, including determinations as to the issuance of additional common or preferred units, and the terms thereof;
- compensation and benefit programs and other human resources policy decisions;
- the payment of distributions on our units; and
- determinations with respect to our tax returns.

Our general partner has the authority to conduct our business and manage our operations. Atlas Energy Group may have conflicts of interest, which may permit it to favor its own interests to our unitholders’ detriment.

Conflicts of interest may arise between our general partner and its affiliates, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner is permitted to favor its own interests and the interests of its owners over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our general partner or any of its affiliates to pursue a business strategy that favors us or to refer any business opportunity to us;
- our general partner is expressly allowed to take into account the interests of parties other than us in resolving conflicts of interest;
- our partnership agreement eliminates any fiduciary duties owed by our general partner to us, and restricts the remedies available to unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of our drilling programs and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership securities and reserves;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner determines the amount and timing of any capital expenditure and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. Our partnership agreement does not set a limit on the amount of maintenance capital expenditures that our general partner may estimate;

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner decides which costs incurred by it and its affiliates are reimbursable by us; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our general partner and affiliates of our general partner may compete with us. This could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our ability to replace reserves, results of operations and cash available for distribution to our unitholders.

Our partnership agreement provides that for so long as it is the general partner of ARP, our general partner's sole business will be to act as a general partner of ARP and any other partnership or limited liability company of which ARP is, directly or indirectly, a partner or member and to undertake activities that are ancillary or related thereto. This restriction does not apply to any person other than our general partner, and our general partner may hold or dispose any interest that it acquires or obtains from any affiliate or unrestricted person (as defined in our partnership agreement), and perform activities in connection holding such interest. Affiliates of our general partner, therefore, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Our general partner owns general and limited partner interests in AGP, an exploration and production development subsidiary, which currently conducts operations in the mid-continent region of the United States as well as interests in entities which incubate new master limited partnerships and invest in existing ones. Our general partner and its affiliates may make future investments and acquisitions that may include entities or assets that we would have been interested in acquiring. In addition, members of management of Atlas Energy Group have substantial experience in the natural gas and oil business.

Therefore, our general partner and its affiliates may compete with us for investment opportunities and our general partner and its affiliates may own an interest in entities that compete with us.

Our partnership agreement provides that:

- affiliates of our general partner have no obligation to refrain from engaging in the same or similar business activities or lines of business we do, doing business with any of our customers or employing or otherwise engaging any of our officers or employees;
- neither our general partner nor any of its officers or directors will be liable to us or to our unitholders for breach of any duty, including any fiduciary duty, by reason of any of these activities; and
- none of our general partner, its affiliates or any of their respective directors or officers is under any duty to present any corporate opportunity to us which may be a corporate opportunity for such person and us, and such person will not be liable to us or our unitholders for breach of any duty, including any fiduciary duty, by reason of the fact that such person pursues or acquires that corporate opportunity for itself, directs that corporate opportunity to another person or does not present that corporate opportunity to us.

Accordingly, our general partner and its affiliates may acquire, develop or dispose of additional natural gas or oil properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. These factors may make it difficult for us to compete with our general partner and its affiliates with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and accordingly cash available for distribution. This also may create actual and potential conflicts of interest between us and our general partner, and its affiliates and result in less than favorable treatment of us.

Certain of our officers and the directors of our general partner may have actual or potential conflicts of interest with us.

Our officers and our general partner’s directors have duties to manage us in a manner beneficial to us, but they also have duties to manage our general partner’s business in a manner beneficial to it. Certain of our non-independent directors and officers also have positions with other affiliates of our general partner. Consequently, these directors and officers may encounter situations in which their obligations to our general partner or one or more of its subsidiaries, on the one hand, and us, on the other hand, are in conflict. Additionally, such directors and officers may own common units of our general partner, options to purchase common units of our general partner or other equity awards, as well as equity of our general partner’s affiliates, which may be significant for some of these persons. Their positions and ownership of such equity and equity awards creates, or may create the appearance of, conflicts of interest when they are faced with decisions that could have different implications for Atlas Energy Group and/or its affiliates than the decisions have for us.

ITEM 1B: UNRESOLVED STAFF COMMENTS
None.

ITEM 2: PROPERTIES
Natural Gas, Oil and NGL Reserves

The following tables summarize information regarding our estimated proved natural gas, oil and NGL reserves as of December 31, 2015. Proved reserves are the estimated quantities of crude oil, natural gas, and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. The estimated reserves include reserves attributable to our direct ownership interests in oil and gas properties as well as the reserves attributable to our percentage interests in the oil and gas properties owned by Drilling Partnerships in which we own partnership interests. All of the reserves are located in the United States. We base these estimated proved natural gas, oil and NGL reserves and future net revenues of natural gas, oil and NGL reserves upon reports prepared by independent third-party reserve engineers. We have adjusted these estimates to reflect the settlement of asset retirement obligations on gas and oil properties. A summary of the reserves report related to our estimated proved reserves at December 31, 2015 is included as Exhibits 99.2 and 99.3 to this report. In accordance with SEC guidelines, we make the standardized measure estimates of future net cash flows from proved reserves using natural gas, oil and NGL sales prices in effect as of the dates of the estimates which are held constant throughout the life of the properties. Our estimates of proved reserves are calculated on the basis of the unweighted adjusted average of the first-day-of-the-month prices for each month during the years ended December 31, 2015 and 2014, and are listed below as of the dates indicated:

	December 31,	
	2015	2014
Unadjusted Prices(1)		
Natural gas (per Mcf)	$2.59	$4.35
Oil (per Bbl)	$50.28	$94.99
Natural gas liquids (per Bbl)	$11.02	$30.21
Average Realized Prices, Before Hedge(1) (2)		
Natural gas (per Mcf)	$2.23	$3.93
Oil (per Bbl)	$44.19	$82.22
Natural gas liquids (per Bbl)	$12.77	$29.39

(1) "Mcf" represents thousand cubic feet; and "Bbl" represents barrels.
(2) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for years ended December 31, 2015 and 2014. Including the effect of this subordination, the average realized sales price was $2.19 per Mcf before the effects of financial hedging and $3.84 per Mcf before the effects of financial hedging for years ended December 31, 2015 and 2014, respectively.

Reserve estimates are imprecise and may change as additional information becomes available. Furthermore, estimates of natural gas, oil and NGL reserves are projections based on engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production and the timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas, oil and NGLs that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

The preparation of our natural gas, oil and NGL reserve estimates was completed in accordance with prescribed internal control procedures by our reserve engineers. For the periods presented, other than for our Rangely assets, Wright and Company, Inc. was retained to prepare a report of proved reserves. The reserve information includes natural gas, oil and NGL reserves which are all located in the United States. The independent reserves engineer’s evaluation was based on more than 39 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions and government regulations. For our Rangely assets, Cawley, Gillespie, and Associates, Inc. was retained to prepare a report of proved reserves. The independent reserves engineer’s evaluation was based on more than 33 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. Our internal control procedures include verification of input data delivered to our third-party reserve specialist, as well as a multi-functional management review. The preparation of reserve estimates was overseen by our Senior Reserve Engineer, who is a member of the Society of Petroleum Engineers and has more than 17 years of natural gas and oil industry experience. The reserve estimates were reviewed and approved by our senior engineering staff and management, with final approval by our President.

Results of drilling, testing and production subsequent to the date of the estimate may justify revision of these estimates. Future prices received from the sale of natural gas, oil and NGLs may be different from those estimated by our independent third-party engineers in preparing its reports. The amounts and timing of future operating and development costs may also differ from those used. Due to these factors, the reserves set forth in the following tables ultimately may not be produced and the proved undeveloped reserves may not be developed within the periods anticipated. The estimated standardized measure values may not be representative of the current or future fair market value of our proved natural gas and oil properties. Standardized measure values are based upon projected cash inflows, which do not provide for changes in natural gas, oil and NGL prices or for the escalation of expenses and capital costs. The meaningfulness of these estimates depends upon the accuracy of the assumptions upon which they were based (see "Item 1A: Risk Factors—Risks Relating to Our Business").

We evaluate natural gas and oil reserves at constant temperature and pressure. A change in either of these factors can affect the measurement of natural gas and oil reserves. We deduct operating costs, development costs and production-related and ad valorem taxes in arriving at the estimated future cash flows. We base the estimates on operating methods and conditions prevailing as of the dates indicated:

	Proved Reserves at December 31,	
	2015	2014
Proved reserves:		
Natural gas reserves (MMcf)[1]:		
Proved developed reserves	567,992	887,819
Proved undeveloped reserves[2]	36,586	168,566
Total proved reserves of natural gas	604,578	1,056,385
Oil reserves (MBbl)[1]:		
Proved developed reserves	25,484	30,538
Proved undeveloped reserves[2]	19,320	17,480
Total proved reserves of oil	44,804	48,018
NGL reserves (MBbl):		
Proved developed reserves	6,334	12,005
Proved undeveloped reserves[2]	1,516	9,752
Total proved reserves of NGL	7,850	21,757
Total proved reserves (MMcfe)[1]	920,504	1,475,035
Standardized measure of discounted future cash flows (in thousands)[3]	$502,769	$1,984,271

(1) "MMcf" represents million cubic feet; "MMcfe" represents million cubic feet equivalents; and "MBbl" represents thousand barrels. Oil and NGLs are converted to gas equivalent basis ("Mcfe") at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

(2) Our ownership in these reserves is subject to reduction as we generally make capital contributions, which includes leasehold acreage associated with our proved undeveloped reserves, to our Drilling Partnerships in exchange for an equity interest in these partnerships, which is approximately 30%, which effectively will reduce our ownership interest in these reserves from 100% to our respective ownership interest as we make these contributions.

(3) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest and income tax expenses, or to depletion, depreciation and amortization. The future cash flows are discounted

using an annual discount rate of 10%. Standardized measure does not give effect to commodity derivative contracts. Because we are a limited partnership, no provision for federal or state income taxes has been included in the December 31, 2015 and 2014 calculations of standardized measure, which is, therefore, the same as the PV-10 value. Standardized measure for the years ended December 31, 2015 and 2014 includes approximately $(23.5) million and $(36.7) million related to the present value of future cash flows plugging and abandonment of wells, including the estimated salvage value. These amounts were not included in the summary reserve report that appear in Exhibits 99.2 and 99.3 in this report.

Proved developed reserves are those reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well. Proved undeveloped reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells on which a relatively major expenditure is required for recompletion.

Proved Undeveloped Reserves ("PUDS")

PUD Locations. As of December 31, 2015, we had 102 PUD locations totaling approximately 162 net Bcfe's of natural gas, oil and NGLs. These PUDS are based on the definition of PUD's in accordance with the SEC's rules allowing the use of techniques that have been proven effective through documented evidence, such as actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty.

Changes in PUDs. Changes in PUDS that occurred during the year ended December 31, 2015 were due to the following:

- addition of approximately 76 Bcfe due to our drilling and leasing activity as well as locations purchased in the Eagle Ford Shale offset by
- negative revisions of approximately 219 Bcfe in PUDs primarily due to the reduction of our five year drilling plans and unfavorable pricing environment.

Development Costs. Costs incurred related to the development of PUDs were approximately $28.0 million, $164.9 million and $103.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. During the years ended December 31, 2015, 2014 and 2013, approximately 21 Bcfe, 41.2 Bcfe and 58.4 Bcfe of our reserves, respectively, were converted from PUDs to proved developed reserves. See "Item 1: Business - Overview" for further information. As of December 31, 2015, there were no PUDs that had remained undeveloped for five years or more. The proved undeveloped reserves disclosed as of December 31, 2015 are included within our five-year development plan and will be developed within five years of the initial disclosure.

Productive Wells

The following table sets forth information regarding productive natural gas and oil wells in which we have a working interest as of December 31, 2015. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of productive wells in which we have an interest, directly or through our ownership interests in Drilling Partnerships and net wells are the sum of our fractional working interests in gross wells, based on the percentage interest we own in the Drilling Partnership that owns the well:

	Number of Productive Wells[(1)(2)]	
	Gross	Net
Appalachia:		
Gas wells	7,581	3,790
Oil wells	456	344
Total	8,037	4,134
Coal-bed Methane[(3)]:		
Gas wells	3,646	2,896
Oil wells	—	—
Total	3,646	2,896
Barnett/Marble Falls:		
Gas wells	643	511
Oil wells	60	38
Total	703	549
Mississippi Lime/Hunton:		
Gas wells	106	60
Oil wells	—	—
Total	106	60
Rangely/Eagle Ford:		
Gas wells	—	—
Oil wells	427	125
Total	427	125
Other operating areas[(4)]:		
Gas wells	759	237
Oil wells	2	1
Total	761	238

Total:		
Gas wells	12,735	7,494
Oil wells	945	508
Total	13,680	8,002

(1) Includes our proportionate interest in wells owned by 60 Drilling Partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 778 wells.
(2) There were no exploratory wells drilled during the years ended December 31, 2015, 2014 and 2013; there were no gross or net dry wells within our operating areas during the year ended December 31, 2015, 2014 and 2013.
(3) Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the Central Appalachian Basin in Virginia and West Virginia.
(4) Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

Developed and Undeveloped Acreage

The following table sets forth information about our developed and undeveloped natural gas and oil acreage as of December 31, 2015. The information in this table includes our proportionate interest in acreage owned by Drilling Partnerships.

	Developed acreage (1)		Undeveloped acreage(2)	
	Gross (3)	Net (4)	Gross (3)	Net (4)
West Virginia	148,789	82,552	7,019	3,447
Pennsylvania	153,396	76,178	2,272	2,240
New Mexico	126,246	126,246	447,713	447,713
Ohio(5)	109,703	101,692	99,379	97,000
Texas	78,469	66,909	47,641	33,396
Alabama	57,600	56,494	3,973	2,383
Colorado	39,778	30,483	20,485	20,485
Indiana	32,835	27,275	38,228	32,537
Wyoming(6)	—	—	—	—
Oklahoma	125,929	95,029	77,798	37,413
Tennessee	20,119	8,409	42,496	42,296
New York	13,244	12,113	20,919	18,898
Virginia	5,240	4,004	2,237	2,086
Other	2,145	983	3,268	3,050
Total	913,493	688,367	813,428	742,944

(1) Developed acres are acres spaced or assigned to productive wells.
(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether such acreage contains proved reserves.
(3) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.
(4) Net acres is the sum of the fractional working interests owned in gross acres. For example, a 50% working interest in an acre is one gross acre but is 0.5 net acres.
(5) Includes Utica Shale natural gas and oil rights on approximately 1,394 net acres under new leases taken in Ohio that remain undeveloped.
(6) County Line acreage sold to Carbon Creek Energy in October 2015.

The leases for our developed acreage generally have terms that extend for the life of the wells, while the leases on our undeveloped acreage have terms that vary from less than one year to five years. There are no concessions for undeveloped acreage as of December 31, 2015. As of December 31, 2015, leases covering approximately 4,702 of our 742,944 net undeveloped acres, or 0.6%, are scheduled to expire on or before December 31, 2016. An additional 1.6% and 0.2% are scheduled to expire in each of the years 2017 and 2018, respectively.

We believe that we hold good and indefeasible title related to our producing properties, in accordance with standards generally accepted in the industry, subject to exceptions stated in the opinions of counsel employed by us in the various areas in which we conduct our activities. We do not believe that these exceptions detract substantially from our use of any property. As is customary in the industry, we conduct only a perfunctory title examination at the time we acquire a property. Before we commence drilling operations, we conduct an extensive title examination and we perform curative work on defects that we deem significant. We or our predecessors have obtained title examinations for substantially all of our managed producing properties. No single property represents a material portion of our holdings.

Our properties are subject to royalty, overriding royalty and other outstanding interests customary in the industry. Our properties are also subject to burdens such as liens incident to operating agreements, taxes, development obligations under natural gas and oil leases, farm-out arrangements and other encumbrances, easements and restrictions. We do not believe that any of these burdens will materially interfere with our use of our properties.

ITEM 3: LEGAL PROCEEDINGS

We are a party to various routine legal proceedings arising out of the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations. See “Item 8: Financial Statements and Supplementary Data - Note 11”.

ITEM 4: MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5: MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are listed on the New York Stock Exchange ("NYSE") and are traded under the ticker symbol "ARP". At the close of business on February 29, 2016, the closing price of our common limited partner units was $0.67, and there were 173 holders of record of our common limited partner units. The following table sets forth the high and low sales price per unit of our common limited partner units as reported by the NYSE and the cash distributions declared by quarter per unit on our common limited partner units for the years ended December 31, 2015 and 2014:

	High	Low	Cash Distribution per Common Limited Partner Declared(1)
Year ended December 31, 2015:			
Fourth quarter	$3.33	$0.65	$ 0.0375
Third quarter	$6.31	$2.23	$ 0.3249
Second quarter	$9.35	$6.19	$ 0.3249
First quarter	$11.49	$7.04	$ 0.3249
Year ended December 31, 2014:			
Fourth quarter	$19.60	$8.42	$ 0.5898
Third quarter	$20.94	$18.74	$ 0.5898
Second quarter	$21.45	$19.00	$ 0.5832
First quarter	$23.18	$20.19	$ 0.5799

(1) The determination of the amount of future cash distributions declared, if any, is at the sole discretion of our General Partner's board of directors and will depend on various factors affecting our financial conditions and other matters the board of directors deems relevant.

In January 2014, our board of directors approved the modification of our cash distribution payment practice to a monthly cash distribution program whereby we would distribute all of our available cash (as defined in the partnership agreement) for that month to our common and preferred unitholders and general partner within 45 days from the month end. Prior to that, we paid quarterly cash distributions within 45 days from the end of each calendar quarter. See "Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations—Cash Distribution Policy".

For information concerning common units authorized for issuance under our long-term incentive plan, see "Item 12: Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters – Equity Compensation Plan Information".

ITEM 6: SELECTED FINANCIAL DATA

The following table presents selected historical consolidated financial data for us and our predecessor, Atlas Energy E&P Operations, as of and for the periods indicated. Atlas Energy E&P Operations consists of the subsidiaries of Atlas Energy that held its natural gas and oil development and production assets and liabilities and its partnership management business, substantially all of which Atlas Energy, L.P. ("Atlas Energy") transferred to us on March 5, 2012. The consolidated statements of operations data for the years ended December 31, 2015, 2014 and 2013, and the consolidated balance sheet data as of December 31, 2015 and 2014, have been derived from our audited consolidated financial statements included in "Item 8: Financial Statements and Supplementary Data". The consolidated statements of operations data for the year ended December 31, 2012 and the consolidated balance sheet data as of December 31, 2013 and 2012 has been derived from our audited consolidated financial statements that are not included in this Form 10-K. The consolidated statements of operations data for the year ended December 31, 2011 and the consolidated balance sheet data as of December 31, 2011 is derived from Atlas Energy E&P Operations' audited consolidated financial statements that are not included in this Form 10-K.

On February 17, 2011, Atlas Energy acquired certain natural gas and oil properties, the partnership management business, and other assets (the "Transferred Business") from Atlas Energy, Inc. ("AEI"), the former owner of Atlas Energy's general partner. Management of Atlas Energy determined that the acquisition of the Transferred Business constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable assets and liabilities of the Transferred Business based upon their fair values with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit)/equity on our consolidated balance sheet. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the Transferred Business would have been included in our consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, we reflected the impact of the acquisition of the Transferred Business on our consolidated financial statements in the following manner:

- Recognized the assets acquired and liabilities assumed from the Transferred Business at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit) /equity;
- Retrospectively adjusted our consolidated financial statements for any date prior to February 17, 2011, the date of acquisition, to reflect our results on a consolidated basis with the results of the Transferred Business as of or at the beginning of the respective period; and
- Adjusted the presentation of our consolidated statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners and the general partner. The Transferred Business' historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by AEI to the underlying business segments, including the Transferred Business. We have reviewed AEI's general and administrative expense allocation methodology, which is based on the relative total assets of AEI and the Transferred Business, for the Transferred Business' historical financial statements prior to the date of acquisition and believe the methodology is reasonable and reflects the approximate general and administrative costs of our underlying business segments.

The following table should be read in conjunction with our and our predecessor's consolidated financial statements and accompanying notes included within "Item 8: Financial Statements and Supplementary Data" and "Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations". Our and our predecessor's consolidated financial information may not be indicative of our future performance and does not necessarily reflect what our financial position and results of operations would have been had Atlas Energy E&P Operations' operated as an independent, publicly traded company during the historical periods presented, including changes that would have occurred in our operations and capitalization as a result of the separation from Atlas Energy.

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per unit data)				
Statement of operations data:					
Revenues:					
Gas and oil production	$356,999	$470,051	$273,604	$92,901	$66,979
Well construction and completion	76,505	173,564	167,883	131,496	135,283
Gathering and processing	7,431	14,107	15,676	16,267	17,746
Administration and oversight	7,812	15,564	12,277	11,810	7,741
Well services	23,822	24,959	19,492	20,041	19,803
Gain on mark-to-market derivatives	267,223	2,819	—	—	—
Other, net	241	590	(14,456)	(4,886)	(30)
Total revenues	740,033	701,654	474,476	267,629	247,522
Costs and expenses:					
Gas and oil production	169,653	182,226	100,098	26,624	17,100
Well construction and completion	66,526	150,925	145,985	114,079	115,630
Gathering and processing	9,613	15,525	18,012	19,491	20,842
Well services	9,162	10,007	9,515	9,280	8,738
General and administrative	65,968	72,349	78,063	69,123	27,536
Chevron transaction expense	—	—	—	7,670	—
Depreciation, depletion and amortization	157,978	239,923	139,783	52,582	30,869
Asset impairment	966,635	573,774	38,014	9,507	6,995
Total costs and expenses	1,445,535	1,244,729	529,470	308,356	227,710
Operating income (loss)	(705,502)	(543,075)	(54,994)	(40,727)	19,812
Interest expense	(102,133)	(62,144)	(34,324)	(4,195)	—
Gain (loss) on asset sales and disposal	(1,181)	(1,869)	(987)	(6,980)	87
Net income (loss)	(808,816)	(607,088)	(90,305)	(51,902)	19,899
Preferred limited partner dividends	(16,469)	(19,267)	(11,992)	(3,063)	—
	$(825,285)	$(626,355)	$(102,297)	$(54,965)	$19,899

Net income (loss) attributable to owner's interest, common limited partners and the general partner					
Balance sheet data (at period end):					
Property, plant and equipment, net	$1,191,611	$2,263,820	$2,182,770	$1,302,228	$520,883
Total assets	1,731,004	2,798,120	2,408,358	1,498,952	702,366
Total debt, including current portion	1,534,482	1,394,460	942,334	351,425	—
Total partners' capital (deficit) / equity	(84,628)	947,537	1,133,733	862,006	457,175
Cash flow data:					
Net cash provided by operating activities	$172,804	$202,823	$123,932	$16,486	$71,437
Net cash used in investing activities	(204,002)	(896,443)	(1,049,606)	(644,278)	(47,509)
Net cash provided by financing activities	17,304	707,039	904,314	596,272	30,780
Capital expenditures	(127,138)	(212,728)	(263,886)	(127,226)	(47,324)
Operating data[1]					
Net production:					
Natural gas (Mcfd)	216,613	238,054	163,971	69,408	31,403
Oil (Bpd)	5,139	3,436	1,329	330	307

67

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per unit data)				
Natural gas liquids (Bpd)	3,155	3,802	3,473	974	444
Total (Mcfed)	266,374	281,486	192,786	77,232	35,912
Average sales price:					
Natural gas (per Mcf)(2):					
Realized price, after hedge(2)(3)	$3.41	$3.76	$3.48	$3.29	$4.98
Realized price, before hedge(2)	$2.23	$3.93	$3.25	$2.60	$4.53
Oil (per Bbl):					
Realized price, after hedge(3)	$84.30	$87.76	$91.01	$94.02	$89.70
Realized price, before hedge	$44.19	$82.22	$95.88	$91.32	$89.07
Natural gas liquids (per Bbl):					
Realized price, after hedge(3)	$22.40	$29.59	$28.71	$31.97	$48.26
Realized price, before hedge	$12.77	$29.39	$29.43	$31.97	$48.26
Production costs (per Mcfe):					
Lease operating expenses(4):	$1.34	$1.27	$1.08	$0.82	$1.09
Production taxes	0.19	0.27	0.18	0.12	0.10
Transportation and compression	0.24	0.25	0.25	0.24	0.43
Total	$1.76	$1.80	$1.50	$1.19	$1.61

(1) "Mcf" represents thousand cubic feet; "Mcfe" represents thousand cubic feet equivalents; "Mcfd" represents thousand cubic feet per day; "Mcfed" represents thousand cubic feet equivalents per day; and "Bbls" and "Bpd" represent barrels and barrels per day.

(2) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effect of this subordination, the average realized gas sales price $3.36 per Mcf ($2.19 per Mcf before the effects of financial hedging), $3.67 per Mcf ($3.84 per Mcf before the effects of financial hedging), $3.23 per Mcf ($3.00 per Mcf before the effects of financial hedging), $2.76 per Mcf ($2.08 per Mcf before the effects of financial hedging) and $4.28 per Mcf ($3.83 per Mcf before the effects of financial hedging) for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively.

(3) Includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015, consisting of $48.6 million associated with natural gas derivative contracts, $35.8 million associated with crude oil derivative contracts, and $8.3 million associated with natural gas liquids derivative contracts for the year ended December 31, 2015 (see "Item 8. Financial Statements – Note 8").

(4) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effects of these costs, total lease operating expenses per Mcfe were $1.32 per Mcfe ($1.74 per Mcfe for total production costs), $1.25 per Mcfe ($1.77 per Mcfe for total production costs), $1.00 per Mcfe ($1.42 per Mcfe for total production costs), $0.58 per Mcfe ($0.94 per Mcfe for total production costs) and $0.77 per Mcfe ($1.33 per Mcfe for total production costs) for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively.

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

The discussion and analysis presented below provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with "Item 6: Selected Financial Data" and "Item 8: Financial Statements and Supplemental Data", which contains our consolidated financial statements.

Unless the context otherwise requires, references below to "Atlas Resource Partners, L.P.," "Atlas Resource Partners," "the Partnership," "we," "us," "our" and "our company", when used for periods prior to March 5, 2012, refer to the subsidiaries and operations that Atlas Energy, L.P. contributed to Atlas Resource Partners in connection with the separation and, when used for periods after that date, refer to Atlas Resource Partners, L.P. and its consolidated subsidiaries. References below to "Atlas Energy" refer to Atlas Energy, L.P. and its consolidated subsidiaries for all periods through February 27, 2015 and Atlas Energy Group, LLC for all periods thereafter, unless the context otherwise requires.

The following discussion may contain forward-looking statements that reflect our plans, estimates and beliefs. Forward-looking statements speak only as of the date the statements were made. The matters discussed in these forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from those made, projected or implied in the forward-looking statements. Factors that could cause or contribute to these differences include those discussed below and in "Item 1A: Risk Factors". We believe the assumptions underlying the consolidated financial statements are reasonable. However, our consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows in the future or what they would have been had our predecessor been a separate, stand-alone company during the periods presented.

BUSINESS OVERVIEW

We are a publicly-traded (NYSE: ARP) Delaware master-limited partnership ("MLP") and an independent developer and producer of natural gas, crude oil and natural gas liquids ("NGL"), with operations in basins across the United States. We sponsor and manage tax-advantaged investment partnerships ("Drilling Partnerships"), in which we coinvest, to finance a portion of our natural gas, crude oil and natural gas liquid production activities.

On February 27, 2015, our general partner, Atlas Energy Group, LLC ("Atlas Energy Group"; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. ("Atlas Energy"), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as "ATLS"). Atlas Energy Group manages our operations and activities through its ownership of our general partner interest. Concurrent with Atlas Energy Group's unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. ("Targa"; NYSE: TRGP) (the "Atlas Merger") and ceased trading. At December 31, 2015, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

In addition to its general and limited partner interest in us, ATLS also holds general and limited partner interests in the following:

- Atlas Growth Partners, L.P. ("AGP"), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale; and
- Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

SUBSEQUENT EVENTS

Senior Note Repurchases. In January and February 2016, we executed transactions to repurchase portions of our senior unsecured notes. Through the end of February 2016, we have repurchased approximately $20.3 million of our 7.75% Senior Notes in 2021 and approximately $12.1 million of our 9.25% Senior Notes for approximately $5.5 million. As a result of these transactions, we will recognize approximately $25.9 million as gain on early extinguishment of debt in the first quarter of 2016.

Cash Distributions. On January 28, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of December 31, 2015. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner and preferred limited partners, respectively, was paid on February 12, 2016 to unitholders of record at the close of business on February 8, 2016.

On February 24, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of January 31, 2016. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of common units and Class C preferred limited units, respectively, will be paid on March 16, 2016 to unitholders of record at the close of business on March 9, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.5390625 per Class D Preferred Unit, or $2.2 million, for the period from October 15, 2015 through January 14, 2016 to Class D Preferred Unitholders of record as of January 4, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.671875 per Class E Preferred Unit, or $0.2 million, for the period from October 15, 2015 through January 14, 2016 to Class E Preferred Unitholders of record as of January 4, 2016.

NYSE Compliance. On January 12, 2016, we were notified by the NYSE that we were not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of the common units had been less than $1.00 for 30 consecutive trading days. We are working to remedy this situation in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE.

RECENT DEVELOPMENTS

Credit Facility Amendment. On November 23, 2015, we entered into an Eighth Amendment to the Second Amended and Restated Credit Agreement (the "Amendment") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amendment amends the Second Amended and Restated Credit Agreement dated July 31, 2013 (as amended from time to time, the "Credit Agreement"). Among other things, the Eighth Amendment:

- reduced the borrowing base under the Credit Agreement from $750.0 million to $700.0 million;
- increased the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- permits the incurrence of third lien debt subject to the satisfaction of certain conditions, including pro forma financial covenant compliance;
- upon the issuance of any third lien debt, reduces the borrowing base by 25% of the stated amount of such third lien debt (other than third lien debt that is used to refinance senior notes, second lien debt and other third lien debt);
- suspends compliance with a maximum ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) until the four fiscal quarter period ending March 31, 2017 and revised the maximum ratio of Total Funded Debt to EBITDA to be 5.75 to 1.00 for the four quarter periods ending March 31, 2017 and June 30, 2017, 5.50 to 1.00 for the four quarter periods ending September 30, 2017 and December 31, 2017, 5.25 to 1.00 for the four quarter period ending March 31, 2018, and 5.00 to 1.00 for each four fiscal quarter period ending thereafter;
- replaced the requirement to maintain compliance with a maximum ratio of Senior Secured Total Funded Debt to EBITDA with a requirement to be in compliance with a maximum ratio of First Lien Debt (as defined in the Credit Agreement) to EBITDA of 2.75 to1.00; and
- reset the distribution to $0.15 per common unit and permits increases to the distribution per common unit if (a) the ratio of Total Funded Debt (as of such date) to EBITDA for the most recent four fiscal quarters is equal to or less than 5.00 to1.00 and (b) the borrowing base utilization is less than or equal to 85%, on a pro forma basis after giving effect to the distribution payment.

A Seventh Amendment to the Credit Agreement was entered into on July 24, 2015. Among other things, the Seventh Amendment redefined EBITDA.

A Sixth Amendment to the Credit Agreement was entered into on February 23, 2015. Among other things, the Sixth Amendment:

- reduced the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;
- permitted the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;
- rescheduled the May 1, 2015 borrowing base redetermination for July 1, 2015;
- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;

- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and
- revised the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

Funding of AGP's Eagle Ford Deferred Purchase Price. In connection with the Eagle Ford Acquisition, we guaranteed the timely payment of the deferred portion of the purchase price that was to be paid by AGP. Pursuant to the agreement between us and AGP, we had the right to receive some or all of the assets acquired by AGP in the event of its failure to contribute its portion of any deferred payments. In connection with the second installment payments, we and AGP amended the purchase and sale agreement to alter the timing and amount of the quarterly installment payments beginning on March 31, 2015 and ending December 31, 2015. On September 21, 2015, we and AGP, in accordance with the terms of the Eagle Ford shared acquisition and operating agreement, agreed that we would fund AGP's remaining two deferred purchase price installments, which were paid on October 1, 2015 and December 31, 2015.

Arkoma Acquisition. On June 5, 2015, we completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). We funded the purchase price through the issuance of 6,500,000 common limited partner units. The Arkoma Acquisition had an effective date of January 1, 2015, however, as the acquisition constituted a transaction between entities under common control, we retrospectively adjusted our consolidated financial statements for dates prior to the date of acquisition to reflect our results on a consolidated basis with the results of the Arkoma assets as of or at the beginning of the respective period.

Issuance of Common Units. In May 2015, in connection with the Arkoma Acquisition, we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.5 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our revolving credit facility (see "Issuance of Units").

Issuance of Preferred Units. In April 2015, we issued 255,000 of our 10.75% Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units") at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. We pay distributions on the Class E Preferred Units at a rate of 10.75% per annum of the stated liquidation preference of $25.00 (see "Issuance of Units").

Second Lien Term Loan Facility. On February 23, 2015, we entered into a Second Lien Credit Agreement (the "Second Lien Credit Agreement") with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"). The Term Loan Facility matures on February 23, 2020.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the last day of the applicable interest period (or, with respect to interest periods of more than three-months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period) for Eurodollar loans and quarterly for ABR loans (see

"Credit Facilities").

CONTRACTUAL REVENUE ARRANGEMENTS

Natural Gas. We market the majority of our natural gas production to gas marketers directly or to third party plant operators who process and market our gas. The sales price of natural gas produced is a function of the market in the area and typically linked to a regional index. The pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline Zone 4 (200 Leg), Transco Leidy Line, Columbia Appalachia, NYMEX and Transco Zone 5;
- Mississippi Lime - Southern Star;
- Barnett Shale and Marble Falls- primarily Waha;

- Raton - ANR, Panhandle, and NGPL;
- Black Warrior Basin - Southern Natural;
- Eagle Ford – Transco Zone 1;
- Arkoma – Enable Gas; and
- Other regions - primarily the Texas Gas Zone SL spot market (New Albany Shale) and the Cheyenne Hub spot market (Niobrara).

We attempt to sell the majority of our natural gas at monthly, fixed index prices and a smaller portion at index daily prices.

We hold firm transportation obligations on Colorado Interstate Gas for the benefit of production from the Raton Basin in the New Mexico/Colorado Area. The total of firm transportation obligations held is approximately 82,500 dth/d under contracts expiring in 2016. We also hold firm transportation obligations on East Tennessee Natural Gas (25,000 dth/d), Columbia Gas Transmission (14,000 dth/d) and Equitrans (12,300 dth/d) for the benefit of production from the central Appalachian Basin under contracts expiring between the years 2016 and 2024. We hold gathering obligations on ETC that was inherited from Cinco in the Eagle Ford acquisition. The total gathering obligations held is 4,750 mcf/d under contracts expiring in 2016.

Crude Oil. Crude oil produced from our wells flows directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. The crude oil is typically sold at the prevailing spot market price for each region, less appropriate trucking/pipeline charges. The oil and natural gas liquids production of our Rangely assets flows into a common carrier pipeline and is sold at prevailing market prices, less applicable transportation and oil quality differentials. We do not have delivery commitments for fixed and determinable quantities of crude oil in any future periods under existing contracts or agreements.

Natural Gas Liquids. NGLs are extracted from the natural gas stream by processing and fractionation plants enabling the remaining "dry" gas to meet pipeline specifications for transport or sale to end users or marketers operating on the receiving pipeline. The resulting plant residue natural gas is sold as indicated above and our NGLs are generally priced and sold using the Mont Belvieu (TX) or Conway (KS) regional processing indices. The cost to process and fractionate the NGLs from the gas stream is typically either a volumetric fee for the gas and liquids processed or a percentage retention by the processing and fractionation facility. We do not have delivery commitments for fixed and determinable quantities of NGLs in any future periods under existing contracts or agreements.

For the year ended December 31, 2015, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC accounted for approximately 21%, 15%, 11% and 11% of our total natural gas, oil and NGL production revenues, respectively, with no other single customer accounting for more than 10% for this period.

Drilling Partnerships. Certain energy activities are conducted by us through, and a portion of our revenues are attributable to, sponsorship of our Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we will recognize a current liability titled "Liabilities Associated with Drilling Contracts" on our consolidated balance sheets. After the Drilling Partnership well is completed and turned in line (i.e. wells that have been drilled, completed, and connected to a gathering system), we are entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees we are entitled to receive for services provided, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%.

72

As the ultimate managing general partner of our Drilling Partnerships, we receive the following Drilling Partnership management fees:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, we receive a 15% mark-up on those costs incurred to drill and complete the wells included within the partnership. Such fees are earned, in accordance with each Drilling Partnership's partnership agreement, and recognized as the services are performed, typically between 60 and 270 days.
- Administration and oversight. For each well drilled by a Drilling Partnership, we receive a fixed fee between \$100,000 and \$500,000, depending on the type of well drilled, which is earned in accordance with each Drilling Partnership's partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of \$75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed; and
- Well services. Each Drilling Partnership pays us a monthly per well operating fee, currently \$1,000 to \$2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed.

Gathering and processing revenue includes gathering fees we charge to the Drilling Partnership wells for our processing plants in the New Albany and the Chattanooga Shales. Generally, we charge a gathering fee to the Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from Drilling Partnerships by approximately 3%.

While the historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by key trends in natural gas and oil production markets. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

The natural gas, oil and natural gas liquids commodity price markets have suffered significant declines during the fourth quarter of 2014 and throughout 2015. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, our ability to make payments on our debt and our ability to make distributions to our unitholders, including ATLS, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas and oil production from particular wells decrease. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce.

RESULTS OF OPERATIONS

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various plays throughout the United States. Through December 31, 2015, we have established production positions in the following operating areas:

- the Appalachia Basin assets, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region;
- coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico and the Black Warrior Basin in central Alabama, where we established a position following our acquisition of certain assets from EP Energy during 2013, as well as the Central Appalachia Basin in West Virginia and Virginia, where we established a position following our acquisition of assets from GeoMet Inc. in May 2014, and the Arkoma Basin in eastern Oklahoma, where we established a position following the Arkoma Acquisition (see “Recent Developments”);
- the Barnett Shale and Marble Falls play, both in the Fort Worth Basin in northern Texas. The Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil.
- the Rangely field in northwest Colorado, a mature tertiary CO_2 flood with low-decline oil production, where we have a 25% non-operated net working interest position following our acquisition on June 30, 2014 (“Rangely Acquisition”);
- the Eagle Ford Shale in south Texas, in which we and AGP acquired acreage and producing wells in November 2014;
- the Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area; and
- our other operating areas, including the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; and the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled and the number of wells we turned in line, both gross and for our interest, during the years ended December 31, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
Gross wells drilled:			
Appalachia – Utica	—	4	3
Barnett/Marble Falls	3	97	75
Eagle Ford	21	2	—
Mississippi Lime	4	26	25
Total	28	129	103
Net wells drilled(1):			
Appalachia – Utica	—	1	1
Barnett/Marble Falls	2	51	55
Eagle Ford	12	1	—
Mississippi Lime	3	14	10
Total	17	67	66
Gross wells turned in line(2)(3):			
Appalachia			
Marcellus Shale	—	—	9
Utica	4	3	5
Barnett/Marble Falls	14	94	82
Eagle Ford	5	—	—
Mississippi Lime	13	22	21
Total	36	119	117
Net wells turned in line(2)(3):			
Appalachia			
Marcellus Shale	—	—	3
Utica	1	1	2
Barnett/Marble Falls	4	53	65
Eagle Ford	4	—	—
Mississippi Lime	6	10	10
Total	15	64	80

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in our Drilling Partnerships.
(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.
(3) There were no exploratory wells drilled during the years ended December 31, 2015, 2014 and 2013; there were no gross or net dry wells within our operating areas during the year ended December 31, 2015, 2014 and 2013.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes and production per day for the years ended December 31, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
Production:(1)(2)(3)			
Appalachia:			
Natural gas (MMcf)	11,655	13,928	13,397
Oil (000's Bbls)	122	139	121
NGLs (000's Bbls)	12	15	8
Total (MMcfe)	12,461	14,852	14,171
Coal-bed Methane:			
Natural gas (MMcf)	47,250	48,288	19,320
Oil (000's Bbls)	—	—	—
NGLs (000's Bbls)	—	—	—
Total (MMcfe)	47,250	48,288	19,320
Barnett/Marble Falls:			
Natural gas (MMcf)	16,505	20,937	23,744
Oil (000's Bbls)	206	389	295
NGLs (000's Bbls)	727	985	1,004
Total (MMcfe)	22,103	29,180	31,539
Rangely/Eagle Ford(4):			
Natural gas (MMcf)	115	64	—
Oil (000's Bbls)	1,394	561	—
NGLs (000's Bbls)	117	63	—
Total (MMcfe)	9,179	3,810	—
Mississippi Lime/Hunton:			
Natural gas (MMcf)	2,398	2,486	1,779
Oil (000's Bbls)	148	156	63
NGLs (000's Bbls)	199	205	118
Total (MMcfe)	4,478	4,648	2,859
Other operating areas:			
Natural gas (MMcf)	1,141	1,187	1,609
Oil (000's Bbls)	6	9	7
NGLs (000's Bbls)	96	121	138
Total (MMcfe)	1,756	1,965	2,477
Total production:			
Natural gas (MMcf)	79,064	86,890	59,849
Oil (000's Bbls)	1,876	1,254	485
NGLs (000's Bbls)	1,151	1,388	1,268
Total (MMcfe)	97,226	102,742	70,367
Production per day:(1)(2)(3)			
Appalachia:			
Natural gas (Mcfd)	31,930	38,160	36,705
Oil (Bpd)	335	381	332
NGLs (Bpd)	33	41	22
Total (Mcfed)	34,139	40,689	38,825

Coal-bed Methane:			
Natural gas (Mcfd)	129,453	132,296	52,933
Oil (Bpd)	—	—	—
NGLs (Bpd)	—	—	—
Total (Mcfed)	129,453	132,296	52,933
Barnett/Marble Falls:			
Natural gas (Mcfd)	45,220	57,361	65,053
Oil (Bpd)	564	1,066	808
NGLs (Bpd)	1,992	2,698	2,751
Total (Mcfed)	60,555	79,946	86,409
Rangely/Eagle Ford(4):			
Natural gas (Mcfd)	315	175	—

	Years Ended December 31,		
	2015	2014	2013
Oil (Bpd)	3,818	1,538	—
NGLs (Bpd)	320	173	—
Total (Mcfed)	25,147	10,438	—
Mississippi Lime/Hunton:			
Natural gas (Mcfd)	6,570	6,810	4,873
Oil (Bpd)	404	427	171
NGLs (Bpd)	546	561	322
Total (Mcfed)	12,269	12,734	7,834
Other operating areas:			
Natural gas (Mcfd)	3,126	3,253	4,408
Oil (Bpd)	17	25	18
NGLs (Bpd)	263	330	378
Total (Mcfed)	4,811	5,384	6,786
Total production per day:			
Natural gas (Mcfd)	216,613	238,054	163,971
Oil (Bpd)	5,139	3,436	1,329
NGLs (Bpd)	3,155	3,802	3,473
Total (Mcfed)	266,374	281,486	192,786

(1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling Partnership's proportionate net revenue interest in these wells.

(2) "MMcf" represents million cubic feet; "MMcfe" represent million cubic feet equivalents; "Mcfd" represents thousand cubic feet per day; "Mcfed" represents thousand cubic feet equivalents per day; and "Bbls" and "Bpd" represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.

(3) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia (excluding the Cedar Bluff area); Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

(4) Rangely includes production from July 1, 2014, the date of the acquisition, through December 31, 2014; Eagle Ford includes production from November 5, 2014, the date of the acquisition, through December 31, 2014. Production per day represents production based on the full 365-day year ended December 31, 2014.

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the years ended December 31, 2015, 2014 and 2013 along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

	Years Ended December 31,		
	2015	2014	2013
Production revenues (in thousands):(1)			
Appalachia:			
Natural gas revenue	$13,062	$40,030	$36,375
Oil revenue	8,115	11,785	10,564
Natural gas liquids revenue	192	599	223
Total revenues	$21,369	$52,414	$47,162
Coal-bed Methane:			
Natural gas revenue	$158,162	$197,831	$72,876
Oil revenue	—	—	—
Natural gas liquids revenue	—	—	—
Total revenues	$158,162	$197,831	$72,876
Barnett/Marble Falls:			
Natural gas revenue	$36,682	$65,562	$70,167
Oil revenue	4,767	35,772	26,578
Natural gas liquids revenue	9,740	26,344	26,929
Total revenues	$51,189	$127,678	$123,674
Rangely/Eagle Ford(6):			
Natural gas revenue	$456	$183	$—
Oil revenue	104,010	47,597	—
Natural gas liquids revenue	4,283	3,254	—
Total revenues	$108,749	$51,034	$—
Mississippi Lime/Hunton:			
Natural gas revenue	$4,625	$10,134	$7,010
Oil revenue	4,885	14,044	6,452
Natural gas liquids revenue	2,909	7,459	5,175
Total revenues	$12,419	$31,637	$18,637
Other operating areas:			
Natural gas revenue	$4,249	$5,180	$6,622
Oil revenue	496	872	566
Natural gas liquids revenue	366	3,405	4,067
Total revenues	$5,111	$9,457	$11,255
Total production revenues:			
Natural gas revenue	$217,236	$318,920	$193,050
Oil revenue	122,273	110,070	44,160
Natural gas liquids revenue	17,490	41,061	36,394
Total revenues	$356,999	$470,051	$273,604
Average sales price:			
Natural gas (per Mcf):(2)			
Total realized price, after hedge(3) (4)	$3.41	$3.76	$3.48

Total realized price, before hedge[3]	$2.23	$3.93	$3.25
Oil (per Bbl):[2]			
Total realized price, after hedge[4]	$84.30	$87.76	$91.01
Total realized price, before hedge	$44.19	$82.22	$95.88
Natural gas liquids (per Bbl):[2]			
Total realized price, after hedge[4]	$22.40	$29.59	$28.71
Total realized price, before hedge	$12.77	$29.39	$29.43
Production costs (per Mcfe):[1] [2]			
Appalachia:			
Lease operating expenses[5]	$1.04	$1.12	$1.08
Production taxes	0.06	0.06	0.07
Transportation and compression	0.26	0.45	0.47

78

	Years Ended December 31,		
	2015	2014	2013
	$ 1.37	$ 1.64	$ 1.62
Coal-bed Methane:			
Lease operating expenses	$ 1.06	$ 1.05	$ 0.89
Production taxes	0.20	0.33	0.23
Transportation and compression	0.32	0.32	0.36
	$ 1.58	$ 1.71	$ 1.48
Barnett/Marble Falls:			
Lease operating expenses	$ 1.27	$ 1.41	$ 1.18
Production taxes	0.17	0.26	0.19
Transportation and compression	0.12	0.06	0.09
	$ 1.56	$ 1.73	$ 1.46
Rangely/Eagle Ford(6):			
Lease operating expenses	$ 3.42	$ 3.63	$ —
Production taxes	0.44	0.64	—
Transportation and compression	0.03	0.01	—
	$ 3.90	$ 4.28	$ —
Mississippi Lime/Hunton:			
Lease operating expenses	$ 1.39	$ 1.46	$ 1.47
Production taxes	0.06	0.14	0.20
Transportation and compression	0.27	0.27	0.15
	$ 1.72	$ 1.87	$ 1.83
Other operating areas:			
Lease operating expenses	$ 0.84	$ 0.82	$ 0.76
Production taxes	0.12	0.23	0.11
Transportation and compression	0.20	0.21	0.19
	$ 1.15	$ 1.26	$ 1.05
Total production costs:			
Lease operating expenses(5)	$ 1.34	$ 1.27	$ 1.08
Production taxes	0.19	0.27	0.18
Transportation and compression	0.24	0.25	0.25
	$ 1.76	$ 1.80	$ 1.50

(1) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia (excluding the Cedar Bluff area); Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

(2) "Mcf" represents thousand cubic feet; "Mcfe" represents thousand cubic feet equivalents; and "Bbl" represents barrels.

(3) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the years ended December 31, 2015, 2014 and 2013. Including the effect of this subordination, the average realized gas sales price was $3.36 per Mcf ($2.19 per Mcf before the effects of financial hedging), $3.67 per Mcf ($3.84 per Mcf before the effects of financial hedging) and $3.23 per Mcf ($3.00 per Mcf before the effects of financial hedging) for the years ended December 31, 2015, 2014 and 2013, respectively.

(4)

Includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015, consisting of $48.6 million associated with natural gas derivative contracts, $35.8 million associated with crude oil derivative contracts, and $8.3 million associated with natural gas liquids derivative contracts for the year ended December 31, 2015 (see “Item 1. Financial Statements – Note 8”).

(5) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for the year ended December 31, 2015, 2014 and 2013. Including the effects of these costs, Appalachia lease operating expenses were $0.88 per Mcfe ($1.21 per Mcfe for total production costs), $0.96 per Mcfe ($1.47 per Mcfe for total production costs) and $0.69 per Mcfe ($1.23 per Mcfe for total production costs) for the years ended December 31, 2015, 2014 and 2013, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $1.32 per Mcfe ($1.74 per Mcfe for total production costs), $1.25 per Mcfe ($1.77 per Mcfe for total production costs) and $1.00 per Mcfe ($1.42 per Mcfe for total production costs) for the years ended December 31, 2015, 2014 and 2013, respectively.

(6) Rangely includes production from July 1, 2014, the date of the acquisition, through December 31, 2014; Eagle Ford includes production from November 5, 2014, the date of the acquisition, through December 31, 2014. Production per day represents production based on the full 365-day year ended December 31, 2014.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Total production revenues were $357.0 million for the year ended December 31, 2015, a decrease of $113.1 million from $470.1 million for the year ended December 31, 2014. This decrease principally consisted of a $76.5 million decrease attributable to the Barnett Shale/Marble Falls operations, a $39.6 million decrease attributable to the coal-bed methane assets, a $31.0 million decrease attributable to the Appalachia assets, a $19.2 million decrease attributable to the Mississippi Lime/Hunton assets, and a $4.3 million decrease associated with our other operating areas, partially offset by a $57.7 million increase attributable to the newly acquired Rangely and Eagle Ford assets.

Total production costs were $169.7 million for the year ended December 31, 2015, a decrease of $12.5 million from $182.2 million for the year ended December 31, 2014. This decrease primarily consisted of a $16.1 million decrease attributable to the Barnett Shale/Marble Falls assets, a $7.9 million decrease attributable to the coal-bed methane assets, a $7.3 million decrease attributable to the Appalachia operations, a $0.9 million decrease attributable to the Mississippi Lime/Hunton assets, and a $0.4 million decrease associated with our other operating areas, partially offset by a $19.5 million increase attributable to the newly acquired Rangely/Eagle Ford assets, and a $0.6 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships. Total production costs per Mcfe decreased to $1.76 per Mcfe for the year ended December 31, 2015 from $1.80 per Mcfe for the comparable prior year period primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Total production revenues were $470.1 million for the year ended December 31, 2014, an increase of $196.5 million from $273.6 million for the year ended December 31, 2013. This increase principally consisted of a $125.0 million increase attributable to the coal-bed methane assets, a $51.0 million increase attributable to the newly acquired Rangely/Eagle Ford assets, a $13.0 million increase attributable to the Mississippi Lime/Hunton assets, a $5.3 million increase attributable to the Appalachia assets due primarily to the Marcellus and Utica Shale wells drilled, and a $4.0 million increase attributable to the Barnett Shale/Marble Falls operations.

Total production costs were $182.2 million for the year ended December 31, 2014, an increase of $82.1 million from $100.1 million for the year ended December 31, 2013. This increase primarily consisted of a $53.7 million increase attributable to production costs associated with the newly acquired coal-bed methane assets, a $16.3 million increase attributable to the newly acquired Rangely/Eagle Ford assets, a $4.4 million increase attributable to the Barnett Shale/Marble Falls assets, a $3.4 million increase attributable to the Mississippi Lime/Hunton assets, a $3.1 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships, and a $1.3 million increase attributable to Appalachia operations. Total production costs per Mcfe increased to $1.80 per Mcfe for the year ended December 31, 2014 from $1.50 per Mcfe for the comparable prior year period primarily as a result of the increases in our oil and natural gas liquids production.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling Partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for Drilling Partnerships we sponsor. The following table presents the amounts of Drilling Partnership investor capital raised and deployed (in thousands), as well as sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Years Ended December 31,		
	2015	2014	2013
Drilling partnership investor capital:			
Raised	$59,277	$166,798	$149,967
Deployed	$76,505	$173,564	$167,883
Average construction and completion:			
Revenue per well	$4,286	$2,227	$3,276
Cost per well	3,727	1,937	2,849
Gross profit per well	$559	$290	$427
Gross profit margin	$9,979	$22,639	$21,898
Partnership net wells associated with revenue recognized[(1)]:			
Appalachia			
Marcellus Shale	—	—	4
Utica	2	3	5
Barnett/Marble Falls	5	60	24
Rangely/Eagle Ford	6	1	—
Mississippi Lime/Hunton	5	14	18
Total	18	78	51

(1) Consists of Drilling Partnership net wells for which well construction and completion revenue was recognized on a percentage of completion basis.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Well construction and completion segment margin was $10.0 million for the year ended December 31, 2015, a decrease of $12.6 million from $22.6 million for the year ended December 31, 2014. This decrease consisted of a $17.4 million decrease related to fewer wells recognized for revenue within our Drilling Partnerships, partially offset by a $4.8 million increase associated with our higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Eagle Ford Shale wells within our Drilling Partnerships during the year ended December 31, 2015 compared with the prior year. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Well construction and completion segment margin was $22.6 million for year ended December 31, 2014, an increase of $0.7 million from $21.9 million for the year ended December 31, 2013. This increase consisted of a $7.7 million increase related to a greater number of wells recognized for revenue within our Drilling Partnerships, partially offset by a $7.0 million decrease associated with lower gross profit margin per well. Average revenue and cost per well decreased between periods due primarily to capital deployed for lower cost Marble Falls wells within the Drilling Partnerships during the year ended December 31, 2014 compared with capital deployed for higher cost Marcellus and Utica Shale wells during the prior year.

At December 31, 2015, our consolidated balance sheet includes $21.5 million of “liabilities associated with well drilling contracts” for funds raised by our Drilling Partnerships that have not been applied to the completion of wells due to the timing of drilling operations, and thus had not been recognized as well construction and completion revenue on our consolidated statement of operations. We expect to recognize this amount as revenue during 2016.

Administration and Oversight

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our Drilling Partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the Drilling Partnerships, such as those in the Marble Falls play, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales. The following table presents the number of gross and net development wells we drilled for our Drilling Partnerships during years ended December 31, 2015, 2014 and 2013. There were no exploratory wells drilled during the years ended December 31, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
Gross partnership wells drilled:			
Appalachia - Utica	—	4	3
Barnett/Marble Falls	2	77	51
Eagle Ford	10	2	21
Mississippi Lime/Hunton	2	17	—
Total	14	100	75
Net partnership wells drilled:			
Appalachia - Utica	—	4	3
Barnett/Marble Falls	2	64	25
Eagle Ford	9	1	—
Mississippi Lime/Hunton	1	16	21
Total	12	85	49

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Administration and oversight fee revenues were $7.8 million for the year ended December 31, 2015, a decrease of $7.8 million from $15.6 million for the year ended December 31, 2014. This decrease was due to a decrease in the number of wells spud within the current year period compared with the prior year period, particularly within the Marble Falls and the Mississippi Lime plays.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Administration and oversight fee revenues were $15.6 million for the year ended December 31, 2014, an increase of $3.3 million from $12.3 million for the year ended December 31, 2013. This increase was due to increases in the number of wells spud within the year ended December 31, 2014 compared with the prior year period, particularly within the Marble Falls play.

Well Services

Well service revenue and expenses represent the monthly operating fees we charge and the work our service company performs, including work performed for our Drilling Partnership wells during the drilling and completing phase as well as ongoing maintenance of these wells and other wells for which we serve as operator.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Well services revenues were $23.8 million for the year ended December 31, 2015, a decrease of $1.2 million from $25.0 million for the year ended December 31, 2014. Well services expenses were $9.2 million for the year ended December 31, 2015, a decrease of

$0.8 million from $10.0 million for the year ended December 31, 2014. The decrease in well services revenue is primarily related to our continued efforts to increase production through intermittent operation of certain legacy wells which results in a reduction of the monthly operating fees which we charge, partially offset by the increased utilization of our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls plays by our Drilling Partnership wells. The decrease in well services expense is primarily related to lower labor and other employee costs.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Well services revenues were $25.0 million for the year ended December 31, 2014, an increase of $5.5 million from $19.5 million for the year ended December 31, 2013. Well services expenses were $10.0 million for the year ended December 31, 2014, an increase of $0.5 million from $9.5 million for the year ended December 31, 2013. The increase in well services revenue is primarily related to the increased utilization of our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls plays by Drilling Partnership wells. The increase in well services expense is primarily related to higher labor costs.

Gathering and Processing

Gathering and processing margin includes gathering fees we charge to our Drilling Partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale. Generally, we charge a gathering fee to our Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Our net gathering and processing expense for the year ended December 31, 2015 was net expense of $2.2 million, an unfavorable movement of $0.8 million compared with net expense of $1.4 million for the year ended December 31, 2014. This unfavorable movement was principally due to lower gathering fees from our Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline, in comparison with the prior year.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Our net gathering and processing expense for the year ended December 31, 2014 was $1.4 million, a decrease of $0.9 million compared with net expense of $2.3 million for the year ended December 31, 2013. This favorable movement was principally due to a full year of gathering fees from the Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline.

Gain on Mark-to-Market Derivatives

On January 1, 2015, we discontinued hedge accounting for our qualified commodity derivatives. As such, subsequent changes in fair value of these derivatives are recognized immediately within gain (loss) on mark-to-market derivatives on our consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners' capital (deficit) on our balance sheet, will be reclassified to our consolidated statements of operations in the future at the time the originally hedged physical transactions settle.

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. We recognized a gain on mark-to-market derivatives of $267.2 million for the year ended December 31, 2015 as compared to a gain on mark-to-market derivatives of $2.8 million for the year ended December 31, 2014. This $264.4 million increase was due to mark-to-market gains in the current year related to the change in natural gas and oil prices during the year.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. We recognized a gain on mark-to-market derivatives of $2.8 million for the year ended December 31, 2014. This gain was due to mark-to-market gains in the year ended December 31, 2014 related to the change in natural gas and oil prices during the year. There were no gains or losses on mark-to-market derivatives during the year ended December 31, 2013.

Other, net

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Other, net for the year ended December 31, 2015 was income of approximately $0.2 million, compared to income of $0.6 million for year ended December 31, 2014.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Other, net for the year ended December 31, 2014 was income of $0.6 million, compared with expense of $14.5 million for the year ended December 31, 2013. The $15.1 million favorable movement compared with the prior year period was primarily related to the $14.5 million of premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from EP Energy in the prior year period.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Total general and administrative expenses decreased to $66.0 million for the year ended December 31, 2015 compared with $72.3 million for the year ended December 31, 2014. This decrease was primarily due to an $8.8 million decrease in the current year period in non-recurring transaction costs related to the acquisitions of assets and a $3.1 million decrease in non-cash stock compensation, partially offset by a $5.3 million increase in syndication expenses.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Total general and administrative expenses decreased to $72.3 million for the year ended December 31, 2014 compared with $78.1 million for the year ended December 31, 2013. This decrease was primarily due to a $12.1 million decrease in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods and a $4.6 million decrease in non-cash compensation expense, partially offset by a $7.0 million increase in salaries, wages and benefits and a $3.9 million increase in other corporate activities due to the growth of our business.

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization decreased to $158.0 million for the year ended December 31, 2015 compared with $239.9 million for the comparable prior year period, which was primarily due to an $84.3 million decrease in our depletion expense.

Total depreciation, depletion and amortization increased to $239.9 million for the year ended December 31, 2014 compared with $139.8 million for the comparable prior year period, which was primarily due to a $96.8 million increase in our depletion expense resulting from the acquisitions we consummated during 2014 and 2013.

The following table presents a summary of our depreciation, depletion and amortization expense and our depletion expense per Mcfe for our operations for the respective periods (in thousands, except for percentage and per Mcfe data):

	Years Ended December 31,		
	2015	2014	2013
Depreciation, depletion and amortization:			
Depletion expense	$145,161	$229,482	$132,727
Depreciation and amortization expense	12,817	10,441	7,056
	$157,978	$239,923	$139,783
Depletion expense:			
Total	$145,161	$229,482	$132,727
Depletion expense as a percentage of gas and oil production revenue	41 %	49 %	49 %
Depletion per Mcfe	$1.49	$2.23	$1.89

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties.

For the year ended December 31, 2015, depletion expense was $145.2 million, a decrease of $84.3 million compared with $229.5 million for the year ended December 31, 2014. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 41% for the year ended December 31, 2015, compared with 49% for the year ended December 31, 2014. Depletion expense per Mcfe decreased to $1.49 for the year ended December 31, 2015, compared to $2.23 for the prior year comparable period. The decreases in depletion expense, depletion expense as a percentage of gas and oil revenues, and depletion expense per Mcfe when compared with the comparable prior year period are the result of the asset impairments recognized at September 30, 2015 and December 31, 2014.

For the year ended December 31, 2014, depletion expense was $229.5 million, an increase of $96.8 million compared with $132.7 million for the year ended December 31, 2013. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 49% for the year ended December 31, 2014, which was consistent with 49%

for the year ended December 31, 2013. Depletion expense per Mcfe increased to $2.23 for the year ended December 31, 2014, compared to $1.89 for the prior year comparable period, which was primarily due to an increase in depletion expense associated with our oil and natural gas liquids wells drilled between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

Asset Impairment

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Asset impairment for the year ended December 31, 2015 was $966.6 million as compared with a $573.8 million impairment for the comparable prior year period. The $966.6 million of asset impairment related to oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, net of $85.8 million of future hedge gains reclassified from accumulated other comprehensive income. In 2014, the $573.8 million of asset impairment primarily consisted of $555.7 million of oil and gas impairment within our Appalachian and mid-continent operations, which was net of $82.3 million of future hedge gains reclassified from accumulated other comprehensive income. In addition, $18.1 million of asset impairment in 2014 was due to goodwill impairment. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Asset impairment for the year ended December 31, 2014 was $573.8 million as compared with $38.0 million for the comparable prior year period. The $573.8 million of asset impairment primarily consisted of $555.7 million of oil and gas impairment within our Appalachian and mid-continent operations, which was net of $82.3 million of future hedge gains reclassified from accumulated other comprehensive income. In addition, $18.1 million of asset impairment is due to goodwill impairment. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014. During the year ended December 31, 2013, we recognized $38.0 million of asset impairment related to impairments of gas and oil properties within property, plant and equipment, net on our consolidated balance sheet primarily for our shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. These impairments related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair values at December 31, 2014 and 2013 and our intention not to drill on certain expiring unproved acreage. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of commodity prices in comparison to their carrying values at December 31, 2014 and 2013.

Interest Expense

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. Interest expense for the year ended December 31, 2015 was $102.1 million as compared with $62.1 million for the comparable prior year period. The $40.0 million increase in our interest expense consisted of a $23.1 million increase associated with our Term Loan Facility, an $8.7 million increase associated with interest expense on our Senior Notes, $5.6 million in accelerated amortization charges related to our reduced credit facility borrowing base and a $3.0 million increase associated with amortization of our deferred financing costs, partially offset by a $0.4 million decrease associated with outstanding borrowings under our revolving credit facility. The increase associated with our Senior Notes is primarily due to the issuance of an additional $100.0 million of our 7.75% Senior Notes due 2021 in June 2014 and an additional $75.0 million of our 9.25% Senior Notes due 2021 in October 2014. The increase in interest expense for our Term Loan Facility related to our entry into the Term Loan Facility in February 2015.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Interest expense for the year ended December 31, 2014 was $62.1 million as compared with $34.3 million for the comparable prior year period. The $27.8 million increase consisted of a $20.7 million increase associated with interest expense on our senior notes, a $6.4 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility, a $0.2 million increase in the amortization of the 7.75% and 9.25% senior notes' discounts, and interest that was capitalized on our ongoing capital projects, partially offset by a $0.4 million decrease associated with amortization of deferred financing costs and a $0.3 million decrease in commitment fees. The increase in interest expense related to our senior notes is primarily due to the issuance of an additional $100.0 million of our 7.75% Senior Notes in June 2014 and an additional $75.0 million of our 9.25% Senior Notes in October 2014, as well as a full year of interest expense related to the $275.0 million 7.75% Senior Notes issued in January 2013 and $250.0 million of 9.25% Senior Notes issued in July 2013.

Loss on Asset Sales and Disposal

Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014. During the year ended December 31, 2015 and 2014, we recognized losses on asset sales and disposal of $1.2 million and $1.9 million, respectively. The $1.2 million loss on asset sales and disposal for the year ended December 31, 2015 was primarily related to the $0.8 million write-down of pipe, pump units and other inventory in Indiana at our New Albany Shale and Black Warrior Basin that are no longer usable, $0.4 million of plugging and abandonment costs for certain wells in the New Albany Shale and a $0.1 million loss on the sale of Indiana at our New Albany Shale inventory to Rex Energy, partially offset by a $0.1 million insurance reimbursement for the Mossy Oak plant fire in Indiana at our New Albany Shale in 2014. The $1.9 million loss on asset sales and disposal for the year ended December 31, 2014 was primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement and a $0.3 million loss on the involuntary conversion of the Mossy Oak compressor station.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. During the years ended December 31, 2014 and 2013, we recognized losses on asset sales and disposal of $1.9 million and $1.0 million, respectively. The $1.9 million loss on asset sales and disposal for the year ended December 31, 2014 was primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement and a $0.3 million loss on the involuntary conversion of the Mossy Oak compressor station. The $1.0 million loss on asset sales and disposal for the year ended December 31, 2013 primarily pertained to a loss on the sale of our Antrim assets in Michigan.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary sources of liquidity are cash generated from operations, capital raised through our Drilling Partnerships, and borrowings under our revolving credit facility (see "Credit Facilities"). Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and distributions to our limited partners and general partner. In general, we expect to fund:

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through cash generated from operations, additional borrowings and capital raised through Drilling Partnerships; and
- debt principal payments through additional borrowings as they become due or by the issuance of additional limited partner units or asset sales.

We rely on cash flow from operations and our credit facilities to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs.

In November 2015, we completed the semi-annual redetermination of our Credit Facility, reducing the borrowing base from $750 million to $700 million. Our next redetermination date is in May 2016. Our borrowing base, and thus our borrowing capacity, under the Credit Facility is impacted by the level of our oil and natural gas reserves. Downward revisions of our oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant.

We believe we have sufficient liquidity from (i) our cash flows from operations (including our hedges scheduled to settle in 2016), (ii) availability under the Credit Facility and (iii) available cash, to fund our capital program, current obligations and projected working capital requirements for 2016. Furthermore, despite the decline in natural gas and oil prices, we believe our derivative contracts, which are primarily fixed price swaps, provide significant commodity price protection on a significant portion of our anticipated natural gas and oil production for 2016.

Our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the Credit Facility, (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all, or (iii) obtain additional capital if required on acceptable terms or at all to fund our capital programs or any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control. The extreme ongoing volatility in the energy industry and commodity prices will likely continue to impact our outlook. Our plans are intended to address the impacts of the current volatility in commodity prices while (i) maintaining sufficient liquidity to fund capital in our core drilling programs, (ii) meeting our debt maturities, and (iii) managing and working to strengthen our balance sheet. We continue to implement various cost saving measures to reduce our capital, operating, and general and administrative costs, including renegotiating contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs. We will continue to be opportunistic and aggressive in managing our cost structure and, in turn, our liquidity to meet our capital and operating needs.

To the extent commodity prices remain low or decline further, or we experience disruptions in the financial markets impacting our longer-term access to or cost of capital, our ability to fund future growth projects may be further impacted. We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. For example, we could (i) elect to repurchase a portion of our outstanding debt in the future for cash through open market repurchases or privately negotiated transactions with certain of our debtholders, or (ii) issue additional secured debt as permitted under our debt agreements, although there is no assurance we would do so. It is also possible additional adjustments to our plan and outlook may occur based on market conditions and our needs at that time, which could include selling assets, liquidating all or a portion of our hedge portfolio, seeking additional partners to develop our assets, reducing or suspending the payments of distributions to unitholders and/or reducing our planned capital program.

Cash Flows – Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014

Net cash provided by operating activities of $172.8 million for the year ended December 31, 2015 represented an unfavorable movement of $30.0 million from net cash provided by operating activities of $202.8 million for the comparable prior year period. The $30.0 million unfavorable movement in net cash provided by operating activities resulted from a $110.9 million unfavorable movement in net loss, excluding non-cash items, partially offset by an $80.9 million favorable movement in working capital. The

$110.9 unfavorable movement in net loss, excluding non-cash items, was principally due to a $201.7 million unfavorable movement in net loss, a $226.8 million unfavorable movement in mark-to-market gain on derivatives subsequent to our discontinuation of hedge accounting on January 1, 2015, an $82.0 million unfavorable movement in depreciation, depletion and amortization, a $3.1 million unfavorable movement in non-cash compensation and a $0.7 million unfavorable movement in loss on asset sales and disposal, partially offset by a $392.9 million asset impairment charge and a $10.5 million favorable movement in amortization of deferred financing costs and discount and premium on long-term debt. The $80.9 million favorable movement in working capital was due to a $210.0 million favorable movement in accounts receivable, prepaid expenses and other, partially offset by a $129.1 million unfavorable movement in accounts payable and accrued liabilities.

Net cash used in investing activities of $204.0 million for the year ended December 31, 2015 represented a favorable movement of $692.4 million from net cash used in investing activities of $896.4 million for the comparable prior year period. This favorable movement was principally due to a $609.0 million decrease in net cash paid for acquisitions and a decrease in capital expenditures of $85.6 million. See further discussion of capital expenditures under “Capital Requirements.”

Net cash provided by financing activities of $17.3 million for the year ended December 31, 2015 represented an unfavorable movement of $681.5 million from net cash provided by financing activities of $698.8 million for the comparable prior year period. This unfavorable movement was principally due to a decrease of $731.7 million for borrowings under our term loans and revolving credit facility, a $332.7 million decrease in net proceeds from issuance of our common limited partner units, a $170.6 million decrease in net proceeds from our senior notes, a $70.5 million decrease in net proceeds from the issuance of our preferred limited partner units, and a $40.2 million unfavorable movement in deferred financing costs, distribution equivalent rights and other, partially offset by a decrease of $593.0 million in repayments under our revolving credit facility and a $71.2 million decrease in cash distributions paid to limited partners. The gross amount of borrowings and repayments under the revolving credit facilities included within net cash provided by financing activities in the consolidated statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under the revolving credit facilities, and payments, which generally occur throughout the period and increase borrowings under our revolving credit facilities, which is generally common practice for our business and industries.

The issuance of $20.0 million in Class D Preferred Units as partial payment for the Eagle Ford Acquisition represented a non-cash transaction during the year ended December 31, 2015.

Cash Flows – Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

Net cash provided by operating activities of $202.8 million for the year ended December 31, 2014 represented a favorable movement of $78.9 million from net cash provided by operating activities of $123.9 million for the prior year. The $78.9 million favorable movement in net cash provided by operating activities resulted from a $110.3 million favorable movement in net income excluding non-cash items, partially offset by a $31.4 million unfavorable movement in working capital. The $110.3 million favorable movement in net income excluding non-cash items consisted principally of a $138.3 million increase in operating cash flow, which was primarily due to our consummation of the EP Energy, GeoMet, Rangely and Eagle Ford acquisitions, partially offset by a $28.0 million increase in cash interest expense principally due to our Senior Notes offerings in July 2013 and June 2014. The $31.4 million unfavorable movement in working capital was principally due to a $65.5 million unfavorable movement in accounts receivable, prepaid expenses and other, partially offset by a $34.1 million favorable movement in accounts payable and accrued liabilities. The $65.5 million unfavorable movement in accounts receivable, prepaid expenses and other was principally due to an unfavorable movement in accounts receivable due to the timing of cash receipts during the year ended December 31, 2014 compared with the year ended December 31, 2013. The $34.1 million favorable movement in accounts payable and accrued liabilities was primarily due to a favorable movement in accounts payable due to the timing of payments and the growth of our business during the year ended December 31, 2014 compared with the year ended December 31, 2013.

Net cash used in investing activities of $896.4 million for year ended December 31, 2014 represented a favorable movement of $153.2 million from net cash used in investing activities of $1,049.6 million for the prior year. This favorable movement was primarily due to a $51.2 million decrease in capital expenditures, a $94.0 million decrease in net cash paid for acquisitions in 2014 as compared to the prior year and an $8.0 million favorable movement in other assets. See further discussion of capital expenditures under “Capital Requirements”.

Net cash provided by financing activities of $707.0 million for the year ended December 31, 2014 represented an unfavorable movement of $197.3 million from net cash provided by financing activities of $904.3 million for the prior year. This movement was principally due to a $339.8 million decrease in net proceeds from long-term debt, a $241.6 million increase in repayments under our revolving credit facility, a $94.1 million increase in cash distributions paid to limited partners, a $69.8 million unfavorable movement in deferred financing costs, distribution equivalent rights and other, and a $9.3 million decrease in net proceeds from the issuance of our preferred limited partner units and warrants, partially offset by a $451.0 million increase in borrowings under our revolving credit facility and a $106.3 million increase in net proceeds from the issuance of our common limited partner units. The gross amount of borrowings and repayments under our revolving credit facility included within net cash provided by financing activities, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under our revolving credit facility, and payments, which generally occur throughout the period and increase borrowings under our revolving credit facility, which is generally common practice for our industry.

The deferred portion of the purchase price related to the Eagle Ford Acquisition represented a non-cash transaction during the year ended December 31, 2014.

Capital Requirements

The capital requirements of our natural gas and oil production consist primarily of:

- Maintenance capital expenditures — oil and gas assets naturally decline in future periods and, as such, we recognize the estimated capitalized cost of stemming such decline in production margin for the purpose of stabilizing our distributable cash flow and cash distributions, which we refer to as maintenance capital expenditures. We calculate the estimate of maintenance capital expenditures by first multiplying forecasted future full year production margin by expected aggregate production decline of proved developed producing wells. Maintenance capital expenditures are then the estimated capitalized cost of wells that will generate an estimated first year margin equivalent to the production margin decline, assuming such wells are connected on the first day of the calendar year. We do not incur specific capital expenditures expressly for the purpose of maintaining or increasing production margin, but such amounts are a subset of hypothetical wells we expect to drill in future periods, including Marcellus Shale, Utica Shale, Mississippi Lime, Marble Falls and Eagle Ford Shale wells, on undeveloped acreage already leased. Estimated capitalized cost of wells included within maintenance capital expenditures are also based upon relevant factors, including historical costs of similar wells and characteristics of each individual well. First year margin from wells included within maintenance capital are also based upon relevant factors, including utilization of public forward commodity exchange prices, current estimates for regional pricing differentials, estimated labor and material rates and other production costs. Estimates for maintenance capital expenditures in the current year are the sum of the estimate calculated in the prior year plus estimates for the decline in production margin from wells connected during the current year and production acquired through acquisitions; and
- Expansion capital expenditures — we consider expansion capital expenditures to be any capital expenditure costs expended that are not maintenance capital expenditures – generally, this will include expenditures to increase, rather than maintain, production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures.

The following table summarizes our maintenance and expansion capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Years Ended December 31,		
	2015	2014	2013
Maintenance capital expenditures	$53,788	$65,300	$31,500
Expansion capital expenditures	73,350	147,428	232,386
Total	$127,138	$212,728	$263,886

During the year ended December 31, 2015, our $127.1 million of total capital expenditures consisted primarily of $51.2 million for wells drilled exclusively for our own account compared with $82.2 million for the comparable prior year period, $32.4 million of investments in our Drilling Partnerships compared with $72.4 million for the prior year comparable period, $11.9 million of leasehold acquisition costs compared with $25.5 million for the prior year comparable period and $31.6 million of corporate and other costs compared with $32.6 million for the prior year comparable period.

During the year ended December 31, 2014, our $212.7 million of total capital expenditures consisted primarily of $82.2 million for wells drilled exclusively for our own account compared with $110.9 million for the prior year, $72.4 million of investments in our Drilling Partnerships compared with $92.3 million for the prior year, $25.5 million of leasehold acquisition costs compared with $20.9 million for the prior year, and $32.6 million of corporate and other costs compared with $39.8 million for the prior year, which primarily related to a decrease in gathering and processing costs.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisitions in the future, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of December 31, 2015, we are committed to expend approximately $7.1 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our Drilling Partnerships and borrowings under our revolving credit facility.

OFF BALANCE SHEET ARRANGEMENTS

As of December 31, 2015, our off-balance sheet arrangements were limited to our letters of credit outstanding of $4.2 million and commitments to spend $7.1 million related to our drilling and completion and capital expenditures, excluding acquisitions.

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of December 31, 2015, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

CASH DISTRIBUTION POLICY

Our partnership agreement requires that we distribute 100% of available cash to our common and preferred unitholders and general partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments. Our general partner is granted discretion under the partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated.

On January 29, 2014, the general partner's board of directors approved a modification to our cash distribution payment practice to a monthly cash distribution program. Monthly cash distributions are paid approximately 45 days following the end of each respective monthly period.

Available cash, as defined in our Partnership Agreement, will generally be distributed as follows:

- first, 98% to our Class D and E preferred unitholders and 2% to our general partner until the distribution to each of our Class D and Class E Preferred Units is an amount equal to its fixed quarterly distribution;
- second, 98% to our Class C preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class C Preferred Unit the greater of $0.51 per quarter and the distribution payable to common unitholders;

- thereafter 98% to our common unitholders and 2% to our general partner.

These distribution percentages are modified to provide for incentive distributions to be paid to our general partner, if quarterly distributions exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The incentive distribution rights will entitle our general partner to receive the following increasing percentage of cash distributed by us as it reaches certain target distribution levels:

- 13.0% of all cash distributed in any quarter after each common unit has received $0.46 for that quarter;
- 23.0% of all cash distributed in any quarter after each common unit has received $0.50 for that quarter; and
- 48.0% of all cash distributed in any quarter after each common unit has received $0.60 for that quarter.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table summarizes our contractual obligations at December 31, 2015 (in thousands):

		Payments Due By Period			
	Total	Less than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Contractual cash obligations:					
Total debt	$1,542,000	$—	$592,000	$250,000	$700,000
Interest on total debt	469,065	103,388	198,746	146,931	20,000
Operating leases	15,874	3,875	6,898	3,252	1,849
Total contractual cash obligations	$2,026,939	$107,263	$797,644	$400,183	$721,849

		Amount of Commitment Expiration Per Period			
	Total	Less than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Other commercial commitments:					
Standby letters of credit	$4,191	$4,191	$—	$—	$—
Other commercial commitments[1]	23,285	9,924	4,827	3,624	4,910
Total commercial commitments	$27,476	$14,115	$4,827	$3,624	$4,910

(1) Our other commercial commitments include our share of drilling and completion commitments and our throughput contracts, including firm transportation obligations for natural gas and gathering commitments as a result of the EP Energy and GeoMet acquisitions. See “Contractual Revenue Arrangements” for a description of our firm transportation obligations.

ENVIRONMENTAL REGULATION

Our operations are subject to federal, state and local laws and regulations governing the release of regulated materials into the environment or otherwise relating to environmental protection or human health or safety (see “Item 1: Business—Environmental Matters and Regulation”). We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; imposition of remedial requirements; issuance of injunctions affecting our operations; or other measures. We have maintained and expect to continue to maintain environmental compliance programs. However, risks of accidental leaks or spills are associated with our operations. There can be no assurance that we will not incur significant costs and liabilities relating to claims for damages to property, the environment, natural resources, or persons resulting from the operation of our and our subsidiaries’ business. Moreover, it is possible other developments, such as increasingly strict federal, state and local environmental laws and regulations and enforcement policies, could result in increased costs and liabilities to us and our subsidiaries.

Environmental laws and regulations have changed substantially and rapidly over the last 25 years, and we anticipate that such changes will continue. Trends in environmental regulation include increased reporting obligations and placing more restrictions and limitations on operations, such as emissions of greenhouse gases and other pollutants; generation and disposal of wastes, including wastes that may have technologically enhanced naturally occurring radioactive materials; and use, storage and handling of chemical substances that may impact human health, the environment and/or threatened or endangered species. Other increasingly stringent environmental restrictions and limitations have resulted in increased operating costs for us and other similar businesses throughout the United States. It is possible that the costs of compliance with environmental laws and regulations may continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly, but there can be no assurance that we will identify and properly anticipate each such change, or that our efforts will prevent material costs, if any, from rising.

CREDIT FACILITIES

Revolving Credit Facility

Credit Facility Amendment. On November 23, 2015, we entered into an Eighth Amendment to the Second Amended and Restated Credit Agreement (the “Amendment”) with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amendment amends the Second Amended and Restated Credit Agreement dated July 31, 2013 (as amended from time to time, the “Credit Agreement”). Among other things, the Eighth Amendment:

- reduced the borrowing base under the Credit Agreement from $750.0 million to $700.0 million;
- increased the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;

- permits the incurrence of third lien debt subject to the satisfaction of certain conditions, including pro forma financial covenant compliance;
- upon the issuance of any third lien debt, reduces the borrowing base by 25% of the stated amount of such third lien debt (other than third lien debt that is used to refinance senior notes, second lien debt and other third lien debt);
- suspends compliance with a maximum ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) until the four fiscal quarter period ending March 31, 2017 and revises the maximum ratio of Total Funded Debt to EBITDA to be 5.75 to 1.00 for the four quarter periods ending March 31, 2017 and June 30, 2017, 5.50 to 1.00 for the four quarter periods ending September 30, 2017 and December 31, 2017, 5.25 to 1.00 for the four quarter period ending March 31, 2018, and 5.00 to 1.00 for each four fiscal quarter period ending thereafter;
- replaced the requirement to maintain compliance with a maximum ratio of Senior Secured Total Funded Debt to EBITDA with a requirement to be in compliance with a maximum ratio of First Lien Debt (as defined in the Credit Agreement) to EBITDA of 2.75 to1.00; and
- reset the distribution to $0.15 per common unit and permits increases to the distribution per common unit if (a) the ratio of Total Funded Debt (as of such date) to EBITDA for the most recent four fiscal quarters is equal to or less than 5.00 to1.00 and (b) the borrowing base utilization is less than or equal to 85%, on a pro forma basis after giving effect to the distribution payment.

A Seventh Amendment to the Credit Agreement was entered into on July 24, 2015. Among other things, the Seventh Amendment redefined EBITDA.

A Sixth Amendment to the Credit Agreement was entered into on February 23, 2015. Among other things, the Sixth Amendment:

- reduced the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;
- permitted the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;
- rescheduled the May 1, 2015 borrowing base redetermination for July 1, 2015;
- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and
- revised the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

Our borrowing base is scheduled for semi-annual redeterminations in May and November of each year. In February 2015, the borrowing base was reduced from $900 million to $750 million in connection with the Sixth Amendment to the Credit Agreement; in July 2015 (the rescheduled redetermination date included in the Sixth Amendment to the Credit Agreement), a determination by the lenders reaffirmed the $750 million borrowing base in connection with the Seventh Amendment to the Credit Agreement; and in November 2015, the borrowing base was reduced from $750 million to $700 million in connection with the Eighth Amendment to the Credit Agreement. The Credit Agreement also provides that our borrowing base will be reduced by 25% of the stated amount of any senior notes issued, or additional second lien debt incurred, after July 1, 2015. In addition, the Credit Agreement provides that our borrowing base will be reduced by 25% of the stated amount of any third lien debt issued (other than third lien debt that is used to refinance senior notes, second lien debt and other third lien debt). At December 31, 2015, $592.0 million was outstanding under the credit facility. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.2 million was outstanding at December 31, 2015. Our obligations under the facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets.

Additionally, obligations under the facility are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor. Borrowings under the credit facility bear interest, at our election, at either an adjusted LIBOR rate plus an applicable margin between 2.00% and 3.00% per annum (which shall change depending on the borrowing base utilization percentage) or the base rate (which is the higher of the bank’s prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.00% per annum (which shall change depending on the borrowing base utilization percentage). We are also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on our consolidated statements of operations. At December 31, 2015, the weighted average interest rate on outstanding borrowings under the credit facility was 3.25%.

The Credit Agreement contains customary covenants including, without limitation, covenants that limit our ability to incur additional indebtedness (but which permits second lien debt in an aggregate principal amount of up to $300.0 million and third lien debt that satisfies certain conditions including pro forma financial covenants), grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merge or consolidate with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. The Credit Agreement also requires us to maintain a ratio of First Lien Debt to EBITDA of 2.75 to 1.00 as set forth in the Eighth Amendment described above, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. We were in compliance with these covenants as of December 31, 2015.

Although we currently expect our sources of capital to be sufficient to meet our near-term liquidity needs, there can be no assurance that the lenders under our credit facility will not reduce the borrowing base to an amount below our outstanding borrowings or that our liquidity requirements will continue to be satisfied, given current oil prices and the discretion of its lenders to decrease our borrowing base. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in some cases, ceased to provide any new funding. If the borrowing base determination in May 2016 results in a borrowing base deficiency and we cannot access the capital markets and repay debt under our credit facility, we may be unable to continue to pay distributions to its unitholders and may take other actions to reduce costs and to raise funds to repay debt, such as selling assets or monetizing derivative contracts

Term Loan Facility

On February 23, 2015, we entered into a Second Lien Credit Agreement with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the “Term Loan Facility”). The Term Loan Facility matures on February 23, 2020. The Term Loan Facility is presented net of unamortized discount of $6.2 million at December 31, 2015.

We have the option to prepay the Term Loan Facility at any time, and is required to offer to prepay the Term Loan Facility with 100% of the net cash proceeds from the issuance or incurrence of any debt and 100% of the excess net cash proceeds from certain asset sales and condemnation recoveries. We are also required to offer to prepay the Term Loan Facility upon the occurrence of a change of control. All prepayments are subject to the following premiums, plus accrued and unpaid interest:

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;
- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the last day of the applicable interest period (or, with respect to interest periods of more than three-months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period) for Eurodollar loans and quarterly for ABR loans. At December 31, 2015, the weighted average interest rate on outstanding borrowings under the term loan facility was 10.0%.

The Second Lien Credit Agreement contains customary covenants including, without limitation, covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in our existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. We were in compliance with these covenants as of December 31, 2015.

Under the Second Lien Credit Agreement, we may elect to add one or more incremental term loan tranches to the Term Loan Facility so long as the aggregate outstanding principal amount of the Term Loan Facility plus the principal amount of any incremental term loan does not exceed $300.0 million and certain other conditions are adhered to. Any such incremental term loans may not mature on a date earlier than February 23, 2020.

Senior Notes

At December 31, 2015, we had $374.6 million outstanding of our 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"). The 7.75% Senior Notes were presented net of a $0.4 million unamortized discount as of December 31, 2015. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, we may redeem the 7.75% Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the indenture governing the 7.75% Senior Notes (the "7.75% Senior Notes Indenture")), plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. Under certain conditions, including if we sell certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, we must offer to repurchase the 7.75% Senior Notes.

On December 29, 2015, we entered into a Third Supplemental Indenture to the 7.75% Senior Notes Indenture following the receipt of requisite consents of the holders of the 7.75% Senior Notes pursuant to a consent solicitation in respect of the 7.75% Senior Notes that commenced on December 10, 2015. As a result of the consent solicitation, we paid a consent fee of $10.00 for each $1,000 in principal amount of the 7.75% Senior Notes for a total of approximately $3.8 million that was capitalized as deferred financing costs.

Consents were received for the purpose of making the following amendments to the 7.75% Senior Notes Indenture:

(1) Increasing the fixed dollar amount in the basket for secured credit facility indebtedness to $1,000.0 million, the approximate amount of secured credit facility indebtedness currently permitted under our secured credit facilities, from $500.0 million. The use of secured indebtedness incurred under such basket in exchange for the 7.75% Senior Notes or the 9.25% Senior Notes (as defined below) will be limited to a maximum amount of $100 million, and the subsidiaries of ours that issued the 7.75% Senior Notes (the "Issuers") will be required to make any offer to exchange the 7.75% Senior Notes for secured indebtedness of the Issuers incurred under such basket to all holders of the 7.75% Senior Notes on a pro rata basis and to make any offer to exchange the 9.25% Senior Notes for secured indebtedness of the Issuers incurred under such basket to all holders of the 9.25% Senior Notes on a pro rata basis.

(2) Adding an additional covenant providing that we will not permit our consolidated senior secured interest expense to exceed the greater of $80 million in any fiscal year or 8.0% of the consolidated senior secured debt outstanding as of the last day of any fiscal year for which audited financial statements have been provided, subject to certain adjustments and cure rights.

(3) Adding a prohibition with respect to certain make-whole, yield maintenance, redemption, repayment or any other payments, premiums, fees or penalties, providing that such payments or premiums shall not be payable after and during the continuance of an event of default, upon the automatic or other acceleration of such indebtedness prior to

its stated maturity date, or after the commencement of a case with respect to the Issuers under bankruptcy law.

At December 31, 2015, we had $324.1 million outstanding of our 9.25% senior unsecured notes due 2021 (“9.25% Senior Notes”). The 9.25% Senior Notes were presented net of a $0.9 million unamortized discount as of December 31, 2015. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time prior to August 15, 2017, we may redeem the 9.25% Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the indenture governing the 9.25% Senior Notes (the “9.25% Senior Notes Indenture”)), plus accrued and unpaid interest, if any. At any time on or after August 15, 2017, we may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, we may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, we may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. Under certain conditions, including if we sell certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, we must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the $75.0 million of 9.25% Senior Notes on October 14, 2014, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 11, 2015. On April 15, 2015, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was subsequently launched on April 15, 2014 and expired on May 13, 2015.

On December 17, 2015, we entered into a Fourth Supplemental Indenture to the 9.25% Senior Notes Indenture following the receipt of requisite consents of the holders of the 9.25% Senior Notes pursuant to a consent solicitation in respect of the 9.25% Senior Notes that commenced on December 10, 2015. As a result of the consent solicitation, we paid a consent fee of $10.00 for each $1,000 in principal amount of the 9.25% Senior Notes for a total of approximately $3.3 million that was capitalized as deferred financing costs.

Consents were received for the primary purpose of increasing the fixed dollar amount in the basket for secured credit facility indebtedness to $1,050.0 million, the approximate amount of secured credit facility indebtedness currently permitted under our secured credit facilities, from $500.0 million. The use of secured indebtedness incurred under such basket in exchange for the 7.75% Senior Notes or the 9.25% Senior Notes will be limited to a maximum amount of $100 million.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several, subject to certain customary automatic release provisions, including, in certain circumstances, the sale or other disposition of all or substantially all the assets of, or all of the equity interests in, the subsidiary guarantor, or the subsidiary guarantor is declared "unrestricted" for covenant purposes, and any subsidiaries of ours, other than the subsidiary guarantors, are minor. There are no restrictions on our ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants including, without limitation, covenants that limit our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We were in compliance with these covenants as of December 31, 2015.

SECURED HEDGE FACILITY

At December 31, 2015, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as the ultimate general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

In addition, it will be an event of default under our revolving credit facility if we, as the ultimate general partner of the Drilling Partnerships, breach an obligation governed by the secured hedge facility, and the effect of such breach is to cause amounts owing under swap agreements governed by the secured hedge facility to become immediately due and payable.

ISSUANCE OF UNITS

In August 2015, we entered into a distribution agreement with MLV & Co. LLC ("MLV") which we terminated and replaced in November 2015, when we entered into a distribution agreement (the "Distribution Agreement") with MLV and FBR Capital Markets & Co. ("FBR" and, together with MLV, the "Agents"). Pursuant to the distribution agreement, we may sell from time to time to or through the Agents our 8.625% Class D Cumulative Redeemable Perpetual Preferred Units ("Class D Preferred Units") and our Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units") and together with the Class D Preferred Units, the "Preferred Units") having an aggregate offering price of up to $100 million. Sales of the Preferred Units, if any, may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act of 1933, as amended, including sales made to or through a market maker other than on an exchange or through an electronic communications network and sales made directly on the NYSE, the existing trading market for the Preferred Units. Under the terms of the distribution agreement, we may sell our Preferred Units from time to time to each Agent as principal for its respective account at a price equal to 97.0% of the volume weighted average price of the Class D Preferred Units or Class E Preferred Units, as applicable, on the date of sale. Upon the sale of Preferred Units to an Agent as principal, we and such Agent will enter into separate terms agreement with respect to such sale.

The Preferred Units may also be offered by the Sales Agent as agents for us at negotiated prices or prevailing market prices at the time of sale. We pay each Agent a commission on Preferred Units sold by it in an agency capacity, which shall not be more than 3.0% of the gross sales price of Preferred Units sold through the Agent as agent for us. Under the August 2015 Distribution Agreement, we issued 90,328 Class D Preferred Units and 1,083 Class E Preferred Units for net proceeds of $0.9 million, net of $0.3 million in commissions and offering expenses paid. Under the November 2015 Distribution Agreement, we did not issue any Class D Preferred Units nor Class E Preferred Units under the preferred equity distribution program for $0.1 million of net offering expenses paid.

In July 2015, the remaining 39,654 Class B Preferred Units were converted into common limited partner units.

In May 2015, in connection with the Arkoma Acquisition (see “Recent Developments”), we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.7 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our revolving credit facility.

In April 2015, we issued 255,000 of our Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million (see “Recent Developments”). We pay cumulative distributions on a quarterly basis at an annual rate of $2.6875 per unit or at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

In October 2014, in connection with the Eagle Ford Acquisition, we issued 3,200,000 Class D Preferred Units at a public offering price of $25.00 per unit, yielding net proceeds of approximately $77.3 million from the offering, after deducting underwriting discounts and estimated offering expenses. We used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition. On March 31, 2015, to partially pay our portion of the quarterly installment related to the Eagle Ford Acquisition, we issued an additional 800,000 Class D Preferred Units directly to the seller at a value of $25.00 per unit. We pay distributions on a quarterly basis, at an annual rate of $2.15625 per unit, or 8.625% of the $25.00 liquidation preference.

The Class D and Class E Preferred Units rank senior to our common units and Class C Preferred Units with respect to the payment of distributions and distributions upon a liquidation event. The Class D and Class E Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by us or converted into our common units in connection with a change in control. At any time on or after October 15, 2019 for the Class D Preferred Units and April 15, 2020 for the Class E Preferred Units, we may, at our option, redeem such preferred units in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we may redeem such preferred units following certain changes of control, as described in the respective Certificates of Designation. If we do not exercise this redemption option upon a change of control, then holders of such preferred units will have the option to convert the preferred units into a number of our common units as set forth in the respective Certificates of Designation. If we exercise any of our redemption rights relating to such preferred units, the holders will not have the conversion right described above with respect to the preferred units called for redemption. Additionally, if at any time our general partner and its affiliates own more than two-thirds of the outstanding class of any limited partner interests, our general partner will have the right, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of such class of limited partner interests held by unaffiliated persons at a price equal to the greater of (1) the highest cash price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and (2) the average of the daily closing prices of the limited partner interests of such class over the 20 trading days preceding the date three days before the date of the mailing of the exercise notice for such call right.

In August 2014, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the Agents. Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to $100.0 million. Sales of common units, if any, may be made in negotiated transactions or transactions that are deemed to be “at-the-market” offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent. During the year ended December 31, 2015, we issued 9,803,451 common limited partner units under the equity distribution program for net proceeds of $44.2 million, net of $1.1 million in commissions and offering expenses paid.

In May 2014, in connection with the Rangely Acquisition, we issued 15,525,000 of our common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of $19.90 per unit, yielding net proceeds of approximately $297.3 million.

In March 2014, in connection with the GeoMet Acquisition, we issued 6,325,000 of our common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of $21.18 per unit, yielding net proceeds of approximately $129.0 million.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making 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 actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depletion, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. We summarize our significant accounting policies within our consolidated financial statements included in “Item 8: Financial Statements and Supplementary Data – Note 2” included in this report. The critical accounting policies and estimates we have identified are discussed below.

Depreciation and Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets. The cost of property, plant and equipment, less estimated salvage value, is generally depreciated on a straight-line basis over the estimated useful lives of the assets. Useful lives are based on historical experience and are adjusted when changes in planned use, technological advances or other factors indicate that a different life would be more appropriate. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively.

Long-lived assets, other than goodwill and intangibles with infinite lives, generally consist of natural gas and oil properties and pipeline, processing and compression facilities and are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. A long-lived asset, other than goodwill and intangibles with infinite lives, is considered to be impaired when the undiscounted net cash flows expected to be generated by the asset are less than its carrying amount. The undiscounted net cash flows expected to be generated by the asset are based upon our estimates that rely on various assumptions, including natural gas and oil prices, production and operating expenses. Any significant variance in these assumptions could materially affect the estimated net cash flows expected to be generated by the asset. As discussed in “General Trends and Outlook” within this section, recent increases in natural gas and oil drilling have driven an increase in the supply of natural gas and oil and put a downward pressure on domestic prices. Further declines in commodity prices may result in additional impairment charges in future periods.

There were no impairments of unproved gas and oil properties recorded by us for the year ended December 31, 2014. During the year ended December 31, 2015, we recognized $6.6 million of asset impairments related to our unproved gas and oil properties within property, plant and equipment, net on our consolidated balance sheet, primarily for our unproved acreage in the New Albany Shale. During the year ended December 31, 2013, we recognized $13.5 million of asset impairments related to our unproved gas and oil properties within property, plant and equipment, net on our consolidated balance sheet, primarily for our unproved acreage in the Chattanooga and New Albany Shales.

For the year ended December 31, 2015, we recognized $960.0 million of asset impairment related to proved oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, net of $85.8 million of future hedge gains reclassified from accumulated other comprehensive income. During the year ended December 31, 2014, we recognized $555.7 million of asset impairments related to proved oil and gas properties within our Appalachian and mid-continent operations, which was net of $82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014 through the impairment testing date in January 2015. During the year ended December 31, 2013, we recognized $24.5 million of asset impairments related to our proved gas and oil properties within property, plant and equipment, net on our consolidated balance sheet for our shallow natural gas wells in the New Albany Shale. These impairments related to the carrying amounts of these gas and oil properties being in excess of our estimate of their fair values at December 31, 2015, 2014 and 2013. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of commodity prices at the date of measurement.

Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions. Additional factors impacting the economic viability of long-lived assets are discussed under "Item 1A: Risk Factors" in this report.

Goodwill and Intangibles with Infinite Lives. Goodwill and intangibles with infinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized if the carrying value of an entity's reporting units exceeds its estimated fair value.

There were no goodwill impairments recognized by us during the years ended December 31, 2015 and 2013. During the year ended December 31, 2014, we recorded an $18.1 million goodwill non-cash impairment loss within asset impairment on our consolidated statement of operations related to an impairment of goodwill in our gas and oil production reporting unit due to a decline in overall commodity prices. These estimates were subjective and based upon numerous assumptions about future operations and market conditions, which are subject to change.

Fair Value of Financial Instruments

We have established a hierarchy to measure our financial instruments at fair value, which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 – Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 – Unobservable inputs that reflect the entity's own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

We use a fair value methodology to value the assets and liabilities for our outstanding derivative contracts. Our commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 fair value measurements.

Liabilities that are required to be measured at fair value on a nonrecurring basis include our asset retirement obligations that are defined as Level 3. Estimates of the fair value of asset retirement obligations are based on discounted cash flows using numerous estimates, assumptions, and judgments regarding the cost, timing of settlement, our credit-adjusted risk-free rate and inflation rates.

During the years ended December 31, 2014 and 2013, we completed several acquisitions of oil and gas properties and related assets. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were measured under our existing methodology for recognizing an estimated liability for the plugging and abandonment of our gas and oil wells (see “Item 1: Financial Statements - Note 6). These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

Reserve Estimates

Our estimates of proved natural gas, oil and natural gas liquids reserves and future net revenues from them are based upon reserve analyses that rely upon various assumptions, including those required by the SEC, as to natural gas, oil and natural gas liquids prices, drilling and operating expenses, capital expenditures and availability of funds. The accuracy of these reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates. We engaged independent third-party reserve engineers to prepare reports of our proved reserves (see “Item 2: Properties”).

Any significant variance in the assumptions utilized in the calculation of our reserve estimates could materially affect the estimated quantity of our reserves. As a result, our estimates of proved natural gas, oil and natural gas liquids reserves are inherently imprecise. Actual future production, natural gas, oil and natural gas liquids prices, revenues, development expenditures, operating expenses and quantities of recoverable natural gas, oil and natural gas liquids reserves may vary substantially from our estimates or estimates contained in the reserve reports and may affect our ability to pay amounts due under our credit facility or cause a reduction in our credit facility. In addition, our proved reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas, oil and natural gas liquids prices, mechanical difficulties, governmental regulation and other factors, many of which are beyond our control. Our reserves and their relation to estimated future net cash flows impact the calculation of impairment and depletion of oil and gas properties. Adjustments to quarterly depletion rates, which are based upon a units of production method, are made concurrently with changes to reserve estimates. Generally, an increase or decrease in reserves without a corresponding change in capitalized costs will have a corresponding inverse impact to depletion expense.

Asset Retirement Obligations

We estimate the cost of future dismantlement, restoration, reclamation and abandonment of our operating assets.

We recognize an estimated liability for the plugging and abandonment of our gas and oil wells and related facilities. We also recognize a liability for our future asset retirement obligations if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. We also consider the estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability is based on our historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free interest rate. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Since there are many variables in estimating asset retirement obligations, we attempt to limit the impact of management’s judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. We have no assets legally restricted for purposes of settling asset retirement obligations. Except for our gas and oil properties, we believe that there are no other material retirement obligations associated with tangible long lived assets.

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in interest rates and commodity prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of the market risk-sensitive instruments were entered into for purposes other than trading.

General

All of our assets and liabilities are denominated in U.S. dollars, and as a result, we do not have exposure to currency exchange risks.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and interest rate cap and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2015. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

We are subject to the risk of loss on our derivative instruments that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the quarterly monitoring of our oil, natural gas and NGLs counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords us netting or set off opportunities to mitigate exposure risk; and (v) when appropriate requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. ARP's assets related to derivatives as of December 31, 2015 represent financial instruments from ten counterparties; all of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of BBB+ or better) credit rating and are lenders associated with our revolving credit facility. Subject to the terms of our revolving credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the revolving credit facility.

Interest Rate Risk. At December 31, 2015, $592.0 million was outstanding under our revolving credit facility and $243.8 million was outstanding under our term loan facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would change our consolidated interest expense for the twelve month period ending December 31, 2016 by approximately $8.4 million.

Commodity Price Risk. Our market risk exposure to commodities is due to the fluctuations in the commodity prices and the impact those price movements have on our financial results. To limit our exposure to changing commodity prices, we use financial derivative instruments, including financial swap and option instruments, to hedge portions of our future production. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under these swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Option instruments are contractual agreements that grant the right, but not the obligation, to purchase or sell commodities at a fixed price for the relevant period.

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our consolidated operating income for the twelve-month period ending December 31, 2016 of approximately $3.1 million.

Realized pricing of our natural gas, oil, and NGL production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production has been volatile and unpredictable for many years. To limit our exposure to changing natural gas, oil and NGL prices, we enter into natural gas and oil swap, put option and costless collar option contracts. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter ("OTC") futures contracts with qualified counterparties. OTC contracts are generally financial contracts which are settled with financial payments or receipts and generally do not require delivery of physical hydrocarbons. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. Crude oil contracts are based on a West Texas Intermediate ("WTI") index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price.

At December 31, 2015, we had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)
2016	53,546,300	$ 4.229
2017	49,920,000	$ 4.219
2018	40,800,000	$ 4.170

2019	15,960,000	$ 4.017

Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)[1]	Average Fixed Price (per MMBtu)[1]
2016	Puts purchased	1,440,000	$ 4.150

99

Natural Gas Liquids – Crude Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)
2016	84,000	$ 85.651
2017	60,000	$ 83.780

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)
2016	1,557,000	$ 81.471
2017	1,140,000	$ 77.285
2018	1,080,000	$ 76.281
2019	540,000	$ 68.371

(1) "MMBtu" represents million British Thermal Units; "Bbl" represents barrels; "Gal" represents gallons.

ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Resource Partners, L.P.

We have audited the accompanying consolidated balance sheets of Atlas Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (collectively, the “Partnership”) as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), changes in partners’ capital (deficit), and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlas Resource Partners, L.P. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership’s internal control over financial reporting as of December 31, 2015, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 4, 2016 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

March 4, 2016

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$1,353	$15,247
Accounts receivable	63,367	114,520
Advances to affiliates	—	6,567
Current portion of derivative asset	159,460	144,259
Subscriptions receivable	19,877	32,398
Prepaid expenses and other	22,935	26,296
Total current assets	266,992	339,287
Property, plant and equipment, net	1,191,611	2,263,820
Goodwill and intangible assets, net	14,095	14,330
Long-term derivative asset	198,262	130,602
Other assets, net	60,044	50,081
Total assets	$1,731,004	$2,798,120
LIABILITIES AND PARTNERS’ CAPITAL (DEFICIT)		
Current liabilities:		
Accounts payable	$49,249	$111,198
Advances from affiliates	9,924	8,816
Liabilities associated with drilling contracts	21,483	40,611
Current portion of derivative payable to Drilling Partnerships	2,574	932
Accrued well drilling and completion costs	26,914	80,404
Accrued interest	25,436	26,452
Distribution payable	4,334	20,876
Deferred acquisition purchase price	—	23,445
Accrued liabilities	22,086	33,406
Total current liabilities	162,000	346,140
Long-term debt	1,534,482	1,394,460
Asset retirement obligations	113,740	107,950
Other long-term liabilities	5,410	2,033
Commitments and contingencies (Note 11)		

Partners' Capital (Deficit):		
General partner's interest	(33,642)	(13,697)
Preferred limited partners' interests	188,739	163,522
Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	(260,276)	605,065
Accumulated other comprehensive income	19,375	191,471
Total partners' capital (deficit)	(84,628)	947,537
Total liabilities and partners' capital (deficit)	$1,731,004	$2,798,120

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31,		
	2015	2014	2013
Revenues:			
Gas and oil production	$356,999	$470,051	$273,604
Well construction and completion	76,505	173,564	167,883
Gathering and processing	7,431	14,107	15,676
Administration and oversight	7,812	15,564	12,277
Well services	23,822	24,959	19,492
Gain on mark-to-market derivatives	267,223	2,819	—
Other, net	241	590	(14,456)
Total revenues	740,033	701,654	474,476
Costs and expenses:			
Gas and oil production	169,653	182,226	100,098
Well construction and completion	66,526	150,925	145,985
Gathering and processing	9,613	15,525	18,012
Well services	9,162	10,007	9,515
General and administrative	65,968	72,349	78,063
Depreciation, depletion and amortization	157,978	239,923	139,783
Asset impairment	966,635	573,774	38,014
Total costs and expenses	1,445,535	1,244,729	529,470
Operating loss	(705,502)	(543,075)	(54,994)
Interest expense	(102,133)	(62,144)	(34,324)
Loss on asset sales and disposal	(1,181)	(1,869)	(987)
Net loss	(808,816)	(607,088)	(90,305)
Preferred limited partner dividends	(16,469)	(19,267)	(11,992)
Net loss attributable to common limited partners and the general partner	$(825,285)	$(626,355)	$(102,297)
Allocation of net loss attributable to common limited partners and the general partner:			
Common limited partners' interest	$(808,780)	$(625,133)	$(105,661)
General partner's interest	(16,505)	(1,222)	3,364
Net loss attributable to common limited partners and the general partner	$(825,285)	$(626,355)	$(102,297)
Net loss attributable to common limited partners per unit:			
Basic	$(8.63)	$(8.37)	$(2.01)

Diluted	$(8.63)	$(8.37)	$(2.01)
Weighted average common limited partner units outstanding:			
Basic	93,745	74,716	52,528
Diluted	93,745	74,716	52,528

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended December 31,		
	2015	2014	2013
Net loss	$(808,816)	$(607,088)	$(90,305)
Other comprehensive income (loss):			
Derivative instruments designated as cash flow hedges:			
Mark-to-market gains during the period	—	238,875	15,828
Reclassification to net loss of mark-to-market gains used to offset asset impairment expense	(85,768)	(82,324)	—
Reclassification to net loss of mark-to-market (gains) losses	(86,328)	7,739	(10,216)
Total other comprehensive income (loss)	(172,096)	164,290	5,612
Comprehensive loss attributable to common and preferred limited partners and the general partner	$(980,912)	$(442,798)	$(84,693)

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL (DEFICIT)

(in thousands, except unit data)

	Preferred Limited Partners' Interest								Common Limited Partners' Interests		Class C Co Limited Partner Wa
	Class B		Class C		Class D		Class E				
ount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants
9	3,836,554	$96,155	—	$—	—	$—	—	$—	43,973,153	$737,253	—
)	—	—	—	—	—	—	—	—	—	64,039	—
	—	—	3,749,986	85,448	—	—	—	—	15,259,174	320,017	562,497
	—	—	—	—	—	—	—	—	215,981	12,630	—
91)	—	(8,018)	—	(2,100)	—	—	—	—	—	(108,923)	—
	—	—	—	—	—	—	—	—	—	(1,939)	—
3	—	8,402	—	3,590	—	—	—	—	—	(105,660)	—
	—	—	—	—	—	—	—	—	—	—	—
2	3,836,554	96,539	3,749,986	86,938	—	—	—	—	59,448,308	917,417	562,497

)	—	—	—	—	—	—	—	—	—	(12,274)	—
	—	—	—	—	3,200,000	77,301	—	—	21,860,000	426,290	—
	—	—	—	—	—	—	—	—	241,733	7,391	—
78)	—	(8)	—	(737)	—	(1,974)	—	—	—	(16,779)	—
502)	—	(9,704)	—	(9,486)	—	—	—	—	—	(184,303)	—
	—	—	—	—	—	—	—	—	—	(2,158)	—
	(3,796,900)	(94,614)	—	—	—	—	—	—	3,796,900	94,614	—
22)	—	8,770	—	8,786	—	1,711	—	—	—	(625,133)	—
	—	—	—	—	—	—	—	—	—	—	—
697)	39,654	$983	3,749,986	$85,501	3,200,000	$77,038	—	$—	85,346,941	$605,065	562,497
	—	—	—	—	—	—	—	—	—	(44,893)	—
	—	—	—	—	890,328	20,911	256,083	5,845	16,303,451	93,635	—
	—	—	—	—	—	—	—		470,615	5,056	—
9	—	8	—	100	—	(231)	—	(172)	—	15,502	—
79)	—	(42)	—	(7,849)	—	(8,492)	—	(345)	—	(126,288)	—

	—	—	—	—	—	—	—	—	—	(558)	—
	(39,654)	(985)	—	—	—	—	—	—	39,859	985	—
505)	—	36	—	7,650	—	8,292	—	491	—	(808,780)	—
	—	—	—	—	—	—	—	—	—	—	—
642)	—	$—	3,749,986	$85,402	4,090,328	$97,518	256,083	$5,819	102,160,866	$(260,276)	562,497

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$(808,816)	$(607,088)	$(90,305)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	157,978	239,923	139,783
Asset impairment	966,635	573,774	38,014
Gain on derivatives	(226,743)	—	4,749
Loss on asset sales and disposal	1,181	1,869	987
Non-cash compensation expense	4,944	8,067	12,680
Amortization of deferred financing costs and discount and premium on long-term debt	19,640	9,191	9,560
Changes in operating assets and liabilities:			
Accounts receivable, prepaid expenses and other	132,559	(77,476)	(11,958)
Accounts payable and accrued liabilities	(74,574)	54,563	20,422
Net cash provided by operating activities	172,804	202,823	123,932
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(127,138)	(212,728)	(263,886)
Net cash paid for acquisitions	(77,854)	(686,811)	(780,857)
Other	990	3,096	(4,863)
Net cash used in investing activities	(204,002)	(896,443)	(1,049,606)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facilities	661,342	1,393,000	942,000
Repayments under credit facilities	(523,000)	(1,116,000)	(874,425)
Distributions paid to unitholders	(147,795)	(218,995)	(124,932)
Net proceeds from long term debt	—	170,596	510,396
Net proceeds from issuance of common limited partner units	93,635	426,290	320,017
Net proceeds from issuance of preferred units	6,778	77,301	86,624
Arkoma transaction adjustment	(44,893)	(12,351)	64,020
Deferred financing costs, distribution equivalent rights and other	(28,763)	(12,802)	(19,386)
Net cash provided by financing activities	17,304	707,039	904,314
Net change in cash and cash equivalents	(13,894)	13,419	(21,360)
Cash and cash equivalents, beginning of year	15,247	1,828	23,188
Cash and cash equivalents, end of year	$1,353	$15,247	$1,828

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the “Partnership”) is a publicly traded (NYSE: ARP) Delaware master-limited partnership (“MLP”) and an independent developer and producer of natural gas, crude oil and natural gas liquids (“NGL”) with operations in basins across the United States. The Partnership sponsors and manages tax-advantaged investment partnerships (the “Drilling Partnerships”), in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities.

On February 27, 2015, the Partnership’s general partner, Atlas Energy Group, LLC (“Atlas Energy Group”; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. (“Atlas Energy”), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as “ATLS”). Atlas Energy Group manages the Partnership’s operations and activities through its ownership of the Partnership’s general partner interest. Concurrent with Atlas Energy Group’s unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. (“Targa”; NYSE: TRGP) (the “Atlas Merger”) and ceased trading. At December 31, 2015, Atlas Energy Group owned 100% of the Partnership’s general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

In addition to its general and limited partner interest in the Partnership, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (“AGP”), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

At December 31, 2015, the Partnership had 102,160,866 common limited partner units issued and outstanding. The common units are a class of limited partner interests in the Partnership. The holders of common units are entitled to participate in partnership distributions, exercise the rights or privileges available to holders of common units and have limited liability as outlined in the partnership agreement.

The partnership agreement authorizes the issuance of an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by the Partnership’s general partner without the approval of the Partnership’s unitholders, subject to the rights of holders of the Partnership’s Class B, Class D and Class E Preferred Units to approve the creation or issuance of any securities senior to such units. The Partnership will continue as a limited partnership until dissolved under the partnership agreement.

The partnership agreement specifies the manner in which the Partnership will make cash distributions to holders of common units and other partnership securities as well as to the general partner in respect of incentive distribution rights (see Note 13).

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a “unit majority” require the approval of a majority of the common units. Except as set forth below, the Partnership’s convertible Class B preferred units, or the Class B Preferred Units, Class C Preferred Units, Class D Preferred Units and Class E Preferred Units have no voting rights and have limited liability. The holder of the Partnership’s Class A Units has all voting rights applicable to the general partner and generally has unlimited liability for obligations of the Partnership.

The following is a summary of the vote requirements specified for certain matters under the Partnership’s partnership agreement (see partnership agreement for full listing of voting requirements):

- Issuance of additional partnership securities – common and preferred unitholders have no approval right
- Amendment of partnership agreement – certain amendments may be made by the Partnership’s general partner without approval of common unitholders. Other amendments generally require the approval of a unit majority or, if any amendment could adversely affect their rights, the approval by a majority of the Class B or Class C Preferred Units or the approval by two-thirds of the Class D Preferred Units or Class E Preferred Units
- Merger or sale of all or substantially all of the Partnership’s assets – unit majority in certain circumstances
- Dissolution of the Partnership - unit majority and the approval by a majority of the Class B and Class C Preferred Units and the approval by two-thirds of the Class D and Class E Preferred Units
- Removal of the general partner - not less than two-thirds of the outstanding common units, including common units held by the Partnership’s general partner and its affiliates

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership's consolidated financial statements include the accounts of the Partnership and its wholly-owned subsidiaries. Transactions between the Partnership and other ATLS operations have been identified in the consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

On June 5, 2015, the Partnership acquired coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma from ATLS (the "Arkoma Acquisition"). Management of the Partnership determined that the Arkoma Acquisition constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable Arkoma assets and liabilities based upon their fair values with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit) on the Partnership's consolidated balance sheets. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the acquisition of Arkoma assets would have been included in the Partnership's consolidated financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior period consolidated financial statements to furnish comparative information. As such, the Partnership reflected the impact of the Arkoma Acquisition on its consolidated financial statements in the following manner:

- Recognized the assets acquired and liabilities assumed from the Arkoma Acquisition at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit);
- Retrospectively adjusted its consolidated financial statements for any date prior to June 5, 2015, the date of acquisition, to reflect its results on a consolidated basis with the results of the Arkoma assets as of or at the beginning of the respective period; and
- Adjusted the presentation of the Partnership's consolidated statements of operations for the years ended December 31, 2015, 2014 and 2013 to reflect the results of operations attributable to the Arkoma assets prior to the date of acquisition to determine income attributable to common limited partners.

Prior to the Arkoma Acquisition, the common limited partners did not participate in the net income (loss) of the Arkoma assets. Subsequent to the Arkoma Acquisition, the common limited partners participate in the net income (loss) of the Arkoma assets retrospectively, which was determined after the deduction of the general partner's and the preferred unitholders' interests. In accordance with the accounting guidance for transactions between entities under common control, the retrospective effect of the restatement of income attributable to common limited partners resulted in a \$0.05 and \$0.02 decrease in net loss attributable to common limited partners per unit for the years ended December 31, 2014 and 2013.

In accordance with established practice in the oil and gas industry, the Partnership's consolidated financial statements include its pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the Drilling Partnerships in which the Partnership has an interest. Such interests generally approximate

30%. The Partnership's consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, the Partnership calculates these items specific to its own economics (see "Property, Plant and Equipment").

Use of Estimates

The preparation of the Partnership's consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership's consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired and liabilities assumed. The oil and gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Actual results could differ from those estimates.

Liquidity and Capital Resources

The Partnership relies on cash flow from operations and its credit facilities to execute its growth strategy and to meet its financial commitments and other short-term liquidity needs.

In November 2015, the Partnership completed the semi-annual redetermination of its Credit Facility, reducing the borrowing base from $750 million to $700 million. The Partnership's next redetermination date is in May 2016. The Partnership's borrowing base, and thus its borrowing capacity, under the Credit Facility is impacted by the level of its oil and natural gas reserves. Downward revisions of its oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of its borrowing base in the future, and these reductions could be significant.

The Partnership believes it has sufficient liquidity from (i) its cash flows from operations (including its hedges scheduled to settle in 2016), (ii) availability under the Credit Facility and (iii) available cash, to fund its capital program, current obligations and projected working capital requirements for 2016. Furthermore, despite the decline in natural gas and oil prices, the Partnership believes its derivative contracts, which are primarily fixed price swaps, provide significant commodity price protection on a significant portion of its anticipated natural gas and oil production for 2016.

The Partnership's ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the Credit Facility, (ii) repay or refinance any of its indebtedness on commercially reasonable terms or at all, or (iii) obtain additional capital if required on acceptable terms or at all to fund its capital programs or any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control. The extreme ongoing volatility in the energy industry and commodity prices will likely continue to impact the Partnership's outlook. The Partnership's plans are intended to address the impacts of the current volatility in commodity prices while (i) maintaining sufficient liquidity to fund capital in its core drilling programs, (ii) meeting its debt maturities, and (iii) managing and working to strengthen its balance sheet. The Partnership continues to implement various cost saving measures to reduce our capital, operating, and general and administrative costs, including renegotiating contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs. The Partnership will continue to be opportunistic and aggressive in managing its cost structure and, in turn, its liquidity to meet its capital and operating needs.

To the extent commodity prices remain low or decline further, or the Partnership experiences disruptions in the financial markets impacting its longer-term access to or cost of capital, its ability to fund future growth projects may be further impacted. The Partnership continually monitors the capital markets and its capital structure and may make changes to its capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. For example, the Partnership could (i) elect to repurchase a portion of its outstanding debt in the future for cash through open market repurchases or privately negotiated transactions with certain of its debtholders, or (ii) issue additional secured debt as permitted under its debt agreements, although there is no assurance the Partnership would do so. It is also possible additional adjustments to its plan and outlook may occur based on market conditions and its needs at that time, which could include selling assets, liquidating all or a portion of its hedge portfolio, seeking additional partners to develop its assets, reducing or suspending the payments of distributions to unitholders and/or reducing its planned capital program.

Cash Equivalents

The Partnership considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments.

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. The Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customers' current creditworthiness. The Partnership extends credit on sales on an unsecured basis to many of its customers. At December 31, 2015 and 2014, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $8.0 million and $8.9 million of inventory at December 31, 2015 and 2014, respectively, which was included within prepaid expenses and other current assets on the Partnership's consolidated balance sheets. The Partnership values inventories at the lower of cost or market. The Partnership's inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

Subscriptions Receivable

The Partnership receives contributions from limited partner investors of its Drilling Partnerships, which are used to fund well drilling activities within the programs. Limited partner investors in the Drilling Partnerships execute an investment agreement with Anthem Securities, Inc. ("Anthem"), a registered broker-dealer and wholly owned subsidiary of the Partnership, through third-party broker dealers, which is then delivered to Anthem. The investor contributions are then remitted to Anthem at a later date. Limited partner investor contributions are non-refundable upon the execution of an investment agreement. The Partnership recognizes the contributions associated with the executed investment agreements but for which contributions have not yet been received at the respective balance sheet date as subscriptions receivable.

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs that generally do not extend the useful life of an asset for two years or more through the replacement of critical components are expensed as incurred. Major renewals and improvements that generally extend the useful life of an asset for two years or more through the replacement of critical components are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset's estimated useful life. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership's results of operations.

The Partnership follows the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs to enhance or evaluate development of proved fields or areas are capitalized. All other geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil and NGLs are converted to gas equivalent basis ("Mcfe") at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

The Partnership's depletion expense is determined on a field-by-field basis using the units-of-production method. Depletion rates for leasehold acquisition costs are based on estimated proved reserves, and depletion rates for well and related equipment costs are based on proved developed reserves associated with each field. Depletion rates are determined based on reserve quantity estimates and the capitalized costs of undeveloped and developed producing properties. Capitalized costs of developed producing properties in each field are aggregated to include the Partnership's costs of property interests in proportionately consolidated Drilling Partnerships, joint venture wells, wells drilled solely by the Partnership for its interests, properties purchased and working interests with other outside operators.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Partnership's consolidated statements of operations. Upon the sale of an individual well, the Partnership credits the proceeds to accumulated depreciation and depletion within its consolidated balance sheets. Upon the Partnership's sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the Partnership's consolidated statements of operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

Impairment of Property, Plant and Equipment

The Partnership reviews its property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

The review of the Partnership's oil and gas properties is done on a field-by-field basis by determining if the historical cost of proved properties less the applicable accumulated depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Partnership's plans to continue to produce and develop proved reserves. Expected future cash flows from the sale of production of reserves are calculated based on estimated future prices. The Partnership estimates prices based upon current contracts in place, adjusted for basis differentials and market related information including published future prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected undiscounted future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, the Partnership's reserve estimates for its investment in the Drilling Partnerships are based on its own assumptions rather than its proportionate share of the limited partnerships' reserves. These assumptions include the Partnership's actual capital contributions, a disproportionate share of salvage value upon plugging of the wells and lower operating and administrative costs.

The Partnership's lower operating and administrative costs result from recognizing its proportionate share of limited partners' Drilling Partnership external operating expenses. These assumptions could result in the Partnership's calculation of depletion and impairment being different than its proportionate share of the Drilling Partnerships' calculations for these items. In addition, reserve estimates for wells with limited or no production history are less reliable than those based on actual production. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information which could cause the assumptions to be modified. The Partnership cannot predict what reserve revisions may be required in future periods.

The Partnership's method of calculating its reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships, which the Partnership sponsors and owns an interest in but does not control. The Partnership's reserve quantities include reserves in excess of its proportionate share of reserves in Drilling Partnerships, which the Partnership may be unable to recover due to the Drilling Partnerships' legal structure. The Partnership may have to pay additional consideration in the future as a Drilling Partnership's wells become uneconomic to the Drilling Partnership under the terms of the Drilling Partnership's drilling and operating agreement in order to recover these excess reserves, in addition to the Partnership becoming responsible for paying associated future operating, development and plugging costs of the well interests acquired, and to acquire any additional residual interests in the wells held by the Drilling Partnership's limited partners. The acquisition of any such uneconomic well interest from the Drilling Partnership by the Partnership is governed under the Drilling Partnership's limited partnership agreement. In general, the Partnership will seek consent from the Drilling Partnership's limited partners to acquire the well interests from the Drilling Partnership based upon the Partnership's determination of fair market value.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds by the Partnership was 6.5%, 5.6% and 6.0% for the years ended December 31, 2015, 2014 and 2013, respectively. The aggregate amount of interest capitalized by the Partnership was $15.8 million, $13.0 million and $14.2 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Intangible Assets

The Partnership recorded its intangible assets with finite lives in connection with partnership management and operating contracts acquired through prior consummated acquisitions. The Partnership amortizes contracts acquired on a declining balance method over their respective estimated useful lives. The Partnership reviews intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset’s estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

The following table reflects the components of intangible assets being amortized at December 31, 2015 and December 31, 2014 (in thousands):

	December 31,		Estimated Useful Lives
	2015	2014	In Years
Gross Carrying Amount	$14,344	$14,344	13
Accumulated Amortization	(13,888)	(13,653)	
Net Carrying Amount	$456	$691	

Amortization expense on intangible assets was $0.2 million, $0.3 million and $0.4 million for the years ended December 31, 2015, 2014 and 2013, respectively. Aggregate estimated annual amortization expense for intangible assets is approximately $0.1 million per year through 2019.

Goodwill

At December 31, 2015 and 2014, the Partnership had $13.6 million of goodwill recorded in connection with its prior consummated acquisitions.

The Partnership tests goodwill for impairment at each year end by comparing its reporting units' estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership's management must apply judgment in determining the estimated fair value of these reporting units. The Partnership's management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership's assets. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership's market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership's management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership's industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership's industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise.

As a result of its goodwill impairment evaluation at December 31, 2014, the Partnership recognized an $18.1 million non-cash impairment charge within asset impairments on its consolidated statement of operations for the year ended December 31, 2014. The goodwill impairment resulted from the reduction in the Partnership's estimated fair value of its gas and oil production reporting unit in comparison to its carrying amount at December 31, 2014. The Partnership's estimated fair value of its gas and oil production reporting unit was impacted by a decline in overall commodity prices during the fourth quarter of 2014. All remaining goodwill at December 31, 2014 and 2015 is attributable to the Partnership's well construction and completion and other partnership management reporting units. No changes in the carrying amount of goodwill were recorded for the years ended December 31, 2015 and 2013.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates (see Note 8). The derivative instruments recorded in the consolidated balance sheets were measured as either an asset or liability at fair value. Changes in a derivative instrument's fair value are recognized currently in the Partnership's consolidated statements of operations unless specific hedge accounting criteria are met. On January 1, 2015, the Partnership discontinued hedge accounting through de-designation for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value after December 31, 2014 of these derivatives are recognized immediately within gain (loss) on mark-to-market derivatives in the Partnership's consolidated statements of operations, while the fair values of the instruments recorded in accumulated other comprehensive income as of December 31, 2014 will be reclassified to the consolidated statements of operations in the periods in which those respective derivative contracts settle. Prior to discontinuance of hedge accounting, the fair value of these commodity derivative instruments was recognized in accumulated other comprehensive income (loss) within partners' capital (deficit) on the Partnership's consolidated balance sheets and reclassified to the Partnership's consolidated statements of operations at the time the originally hedged physical transactions affected earnings.

Asset Retirement Obligations

The Partnership recognizes an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities (see Note 6). The Partnership recognizes a liability for its future asset retirement obligations in the current period if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

Income Taxes

The Partnership is not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership's taxable income. Such taxable income may vary substantially from net income reported in the consolidated financial statements. Certain corporate subsidiaries of the Partnership are subject to federal and state income tax. The federal and state income taxes related to the Partnership and these corporate subsidiaries were immaterial to the consolidated financial statements and are recorded in pre-tax income on a current basis only. Accordingly, no federal or state deferred income tax has been provided for in the consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the years ended December 31, 2015, 2014 and 2013.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2011. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2015.

Unit-Based Compensation

The Partnership recognizes all unit-based payments to employees, including grants of employee unit options, in the consolidated financial statements based on their fair values (see Note 14).

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners, which is determined after the deduction of the general partner's and the preferred unitholders' interests, by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, income (loss) attributable to preferred limited partners and net income (loss) attributable to the general partner's Class A units. The general partner's interest in net income (loss) is calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 13), with a priority allocation of net income to the general partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the general partner's and limited partners' ownership interests.

The Partnership presents net income (loss) per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights' share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management of the Partnership believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Unvested unit-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. Phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plan (see Note 14), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights would result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award's vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. As such, the net income utilized in the calculation of net income (loss) per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net income (loss) allocated to the common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands, except unit data):

	Years Ended December 31,		
	2015	2014	2013
Net income (loss)	$(808,816)	$(607,088)	$(90,305)
Preferred limited partner dividends	(16,469)	(19,267)	(11,992)
Net loss attributable to common limited partners and the general partner	(825,285)	(626,355)	(102,297)
Less: General partner's interest	16,505	1,222	(3,364)
Net loss attributable to common limited partners	(808,780)	(625,133)	(105,661)
Less: Net income attributable to participating securities – phantom units[1]	—	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Basic	(808,780)	(625,133)	(105,661)
Plus: Convertible preferred limited partner dividends[1]	—	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Diluted	$(808,780)	$(625,133)	$(105,661)

(1) Net income (loss) attributable to common limited partners' ownership interests is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the years ended December 31, 2015, 2014 and 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 453,000, 783,000 and 900,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity. For the years ended December 31, 2015, 2014 and 2013, distributions on the Partnership's Class B and Class C convertible preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, convertible preferred units and warrants, as calculated by the treasury stock or if converted methods, as applicable. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership's long-term incentive plan (see Note 14).

The following table sets forth the reconciliation of the Partnership's weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Years Ended December 31,		
	2015	2014	2015
Weighted average number of common limited partner units—basic	93,745	74,716	52,528
Add effect of dilutive incentive awards[1]	—	—	—
Add effect of dilutive convertible preferred limited partner units[2]	—	—	—
Weighted average number of common limited partner units—diluted	93,745	74,716	52,528

(1) For the years ended December 31, 2015, 2014 and 2013, approximately 453,000 units, 783,000 units and 900,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

(2) For the years ended December 31, 2015, 2014 and 2013, potential common limited partner units issuable upon conversion of the Partnership's Class B preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. For the years ended December 31, 2015, 2014 and 2013, potential common limited partner units issuable upon (a) conversion of the Partnership's Class C preferred units and (b) exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As the Class D and Class E preferred units are convertible only upon a change of control event, they are not considered dilutive securities for earnings per unit purposes.

Environmental Matters

The Partnership and its subsidiaries are subject to various federal, state and local laws and regulations relating to the protection of the environment. Management has established procedures for the ongoing evaluation of the Partnership's and its subsidiaries' operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. The Partnership and its subsidiaries maintain insurance which may cover in whole or in part certain environmental expenditures. The Partnership and its subsidiaries had no environmental matters requiring specific disclosure or requiring the recognition of a liability for the years ended December 31, 2015, 2014 and 2013.

Concentration of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist principally of periodic temporary investments of cash and cash equivalents. The Partnership places its temporary cash investments in high-quality short-term money market instruments and deposits with high-quality financial institutions and brokerage firms. At December 31, 2015 and 2014, the Partnership had $10.3 million and $17.2 million, respectively, in deposits at various banks, of which $8.4 million and $14.9 million, respectively, were over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments to date.

Cash on deposit at various banks may differ from the balance of cash and cash equivalents at period end due to certain reconciling items, including any outstanding checks as of period end.

The Partnership sells natural gas, crude oil and NGLs under contracts to various purchasers in the normal course of business. For the year ended December 31, 2015, the Partnership had four customers within its gas and oil production segment that individually accounted for approximately 21%, 15%, 11% and 11%, respectively, of the Partnership natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2014, the Partnership had four customers within its gas and oil production segment that individually accounted for approximately 25%, 15%, 14% and 13%, respectively, of the Partnership natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2013, the Partnership had three customers within its gas and oil production segment that individually accounted for approximately 19%, 11% and 10% of the Partnership's natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity.

The Partnership is subject to the risk of loss on its derivative instruments that it would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. The Partnership maintains credit policies with regard to its counterparties to minimize its overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the quarterly monitoring of its oil, natural gas and NGLs counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords it netting or set off opportunities to mitigate exposure risk; and (v) when appropriate requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. The Partnership's assets related to derivatives as of December 31, 2015 represent financial instruments from ten counterparties; all of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of BBB+ or better) credit rating and are lenders associated with our revolving credit facility. Subject to the terms of their revolving credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the revolving credit facility.

Revenue Recognition

Natural gas and oil production. The Partnership generally sells natural gas, crude oil and NGLs at prevailing market prices. Typically, the Partnership's sales contracts are based on pricing provisions that are tied to a market index, with certain fixed adjustments based on proximity to gathering and transmission lines and the quality of its natural gas. Generally, the market index is fixed two business days prior to the commencement of the production month. Revenue and the related accounts receivable are recognized when produced quantities are 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. Revenues from the production of natural gas, crude oil and NGLs, in which the Partnership has an interest with other producers, are recognized on the basis of its percentage ownership of the working interest and/or overriding royalty.

Drilling Partnerships. Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by the Partnership is deployed to drill and complete wells included within the partnership. As the Partnership deploys Drilling Partnership investor capital, it recognizes certain management fees it is entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if the Partnership has Drilling Partnership investor capital that has not yet been deployed, it will recognize a current liability titled "Liabilities Associated with Drilling Contracts" on the Partnership's consolidated balance sheets. After the Drilling Partnership well is completed and turned in line (i.e. wells that have been drilled, completed, and connected to a gathering system), the Partnership is entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees it is entitled to receive for services provided, the Partnership is also entitled to its pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%. The Partnership recognizes its Drilling Partnership management fees in the following manner:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, the Partnership receives a 15% mark-up on those costs incurred to drill and complete wells included within the partnership. Such fees are earned, in accordance with each Drilling Partnership's partnership agreement, and recognized as the services are performed, typically between 60 and 270 days.
- Administration and oversight. For each well drilled by a Drilling Partnership, the Partnership receives a fixed fee between \$100,000 and \$500,000, depending on the type of well drilled, which is earned in accordance with each Drilling Partnership's partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays the Partnership a monthly per well administrative fee of \$75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed.

- Well services. Each Drilling Partnership pays the Partnership a monthly per well operating fee, currently $1,000 to $2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed.

While the historical structure has varied, the Partnership has generally agreed to subordinate a portion of its share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of cumulative unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. The Partnership periodically compares the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, the Partnership recognizes subordination as an estimated reduction of its pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which the Partnership has recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, the Partnership will recognize an estimated increase in its portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

Gathering and processing revenue. Gathering and processing revenue includes gathering fees the Partnership charges to the Drilling Partnership wells for the Partnership's processing plants in the New Albany and the Chattanooga Shales. Generally, the Partnership charges a gathering fee to the Drilling Partnership wells equivalent to the fees the Partnership remits. In Appalachia, a majority of the Drilling Partnership wells are subject to a gathering agreement, whereby the Partnership remits a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, the Partnership charges the Drilling Partnership wells a 13% gathering fee. As a result, some of the Partnership's gathering expenses, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

The Partnership's gas and oil production operations accrue unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see "Use of Estimates" for further description). The Partnership had unbilled revenues at December 31, 2015 and 2014 of $37.7 million and $84.7 million, respectively, which were included in accounts receivable within the Partnership's consolidated balance sheets.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as "other comprehensive income (loss)" on the Partnership's consolidated financial statements, and for all periods presented, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 8). The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss).

Recently Issued Accounting Standards

In February 2016, the Financial Accounting Standards Board ("FASB") updated the accounting guidance related to leases. The updated accounting guidance requires lessees to recognize a lease asset and liability at the commencement date of all leases (with the exception of short-term leases), initially measured at the present value of the lease payments. The updated guidance is effective for the Partnership as of January 1, 2019 and requires a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest period presented. The Partnership is currently in the process of determining the impact that the updated accounting guidance will have on its consolidated financial statements.

In August 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs specific to line of credit arrangements. The updated accounting guidance allows the option of presenting deferred debt issuance costs related to line-of-credit arrangements as an asset, and subsequently amortizing over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. The Partnership adopted the updated accounting guidance effective January 1, 2016 and does not expect it to have a material impact on its consolidated financial statements.

In April 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs. The updated accounting guidance requires that debt issuance costs be presented as a direct deduction from the associated debt obligation. The Partnership adopted this accounting guidance upon its effective date of January 1, 2016, which will result a reclassification of unamortized deferred financing costs of $31.1 million from other assets to long-term debt on its consolidated balance sheet at December 31, 2015, when included in future filings.

In April 2015, the FASB updated the accounting guidance for earnings per unit (“EPU”) of master limited partnerships (“MLP”) applying the two-class method. The updated accounting guidance specifies that for general partner transfers (or “drop downs”) to an MLP accounted for as a transaction between entities under common control, the earnings (losses) of the transferred business before the date of the transaction should be allocated entirely to the general partner’s interest, and previously reported EPU of the limited partners should not change. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the drop down transaction occurs are also required. The Partnership adopted this accounting guidance upon its effective date of January 1, 2016, and does not expect it to have a material impact on its consolidated financial statements.

In February 2015, the FASB updated the accounting guidance related to consolidation under the variable interest entity and voting interest entity models. The updated accounting guidance modifies the consolidation guidance for variable interest entities, limited partnerships and similar legal entities. The Partnership adopted this accounting guidance upon its effective date of January 1, 2016, and does not except it to have a material impact on its consolidated financial statements.

In August 2014, the FASB updated the accounting guidance related to the evaluation of whether there is substantial doubt about an entity's ability to continue as a going concern. The updated accounting guidance requires an entity's management to evaluate whether there are conditions or events that raise substantial doubt about its ability to continue as a going concern within one year from the date the financial statements are issued and provide footnote disclosures, if necessary. The Partnership adopted this accounting guidance upon its effective date of January 1, 2016, and will provide enhanced disclosures, as applicable, within its consolidated financial statements.

In May 2014, the FASB updated the accounting guidance related to revenue recognition. The updated accounting guidance provides a single, contract-based revenue recognition model to help improve financial reporting by providing clearer guidance on when an entity should recognize revenue, and by reducing the number of standards to which an entity has to refer. In July 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The updated accounting guidance provides companies with alternative methods of adoption. The Partnership is currently in the process of determining the impact that the updated accounting guidance will have on its consolidated financial statements and its method of adoption.

NOTE 3 – ACQUISITIONS

Rangely Acquisition

On June 30, 2014, the Partnership completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado from Merit Management Partners I, L.P., Merit Energy Partners III, L.P. and Merit Energy Company, LLC (collectively, "Merit Energy") for approximately $408.9 million in cash, net of purchase price adjustments (the "Rangely Acquisition"). The purchase price was funded through borrowings under the Partnership's revolving credit facility, the issuance of an additional $100.0 million of its 7.75% senior notes due 2021 ("7.75% Senior Notes") (see Note 7) and the issuance of 15,525,000 common limited partner units (see Note 12). The Rangely Acquisition had an effective date of April 1, 2014. The Partnership's consolidated financial statements reflected the operating results of the acquired business commencing June 30, 2014 with the transaction closing.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $11.6 million of transaction fees, which were included with common limited partners' interests for the year ended December 31, 2014 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

The following table presents the values assigned to the assets acquired and liabilities assumed in the acquisition, based on their estimated fair values at the date of the acquisition (in thousands):

Assets:	
Prepaid expenses and other	$4,041
Property, plant and equipment	405,416
Other assets, net	2,888
Total assets acquired	$412,345
Liabilities:	
Accrued liabilities	2,117
Asset retirement obligation	1,305
Total liabilities assumed	3,422
Net assets acquired	$408,923

EP Energy Acquisition

On July 31, 2013, the Partnership completed an acquisition of assets from EP Energy E&P Company, L.P. ("EP Energy") for approximately $709.6 million in cash, net of purchase price adjustments (the "EP Energy Acquisition"). The purchase price was funded through borrowings under the Partnership's revolving credit facility, the issuance of the Partnership's 9.25% senior notes due August 15, 2021 ("9.25% Senior Notes") (see Note 7), and the issuance of 14,950,000 common limited partner units and 3,749,986 newly created Class C convertible preferred units (see Note 12). The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013. The Partnership's consolidated financial statements reflected the operating results of the acquired business commencing July 31, 2013 with the transaction closing.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $12.1 million of transaction fees which were included within common limited partners' interests for the year ended December 31, 2013 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

The following table presents the values assigned to the assets acquired and liabilities assumed in the acquisition, based on their estimated fair values at the date of the acquisition (in thousands):

Assets:	
Prepaid expenses and other	$5,268
Property, plant and equipment	723,842
Total assets acquired	$729,110
Liabilities:	
Accounts payable	2,747
Asset retirement obligation	16,728
Total liabilities assumed	19,475
Net assets acquired	$709,635

Pro Forma Financial Information

The following data presents pro forma revenues, net income (loss) and basic and diluted net income (loss) per unit for the Partnership as if the Rangely and EP Energy acquisitions, including the related borrowings, net proceeds from the issuance of debt and issuances of common and preferred units had occurred on January 1, 2013. The Partnership prepared these pro forma unaudited financial results for comparative purposes only; they may not be indicative of the results that would have occurred if the Rangely and EP Energy acquisitions and related offerings had occurred on January 1, 2013 or the results that will be attained in future periods (in thousands, except per unit data; unaudited):

	Years Ended December 31, 2014	2013
Total revenues and other	$747,655	$656,677
Net loss	(588,823)	(21,144)
Net loss attributable to common limited partners	(588,353)	(26,131)
Net loss attributable to common limited partners per unit:		
Basic and Diluted	$(7.28)	$(0.32)

Other Acquisitions:

Arkoma Acquisition

On June 5, 2015, the Partnership completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). The Partnership funded the purchase price through the issuance of 6,500,000 common limited partner units (see Note 12). The Arkoma Acquisition had an effective date of January 1, 2015. The Partnership accounted for the Arkoma Acquisition as a transaction between entities under common control (see Note 2).

Eagle Ford Acquisition

On November 5, 2014, the Partnership and AGP completed an acquisition of oil and natural gas liquid interests in the Eagle Ford Shale in Atascosa County, Texas from Cima Resources, LLC and Cinco Resources, Inc. (together “Cinco”) for $342.0 million, net of purchase price adjustments (the “Eagle Ford Acquisition”). Approximately $183.1 million was paid in cash by the Partnership and $19.9 million was paid by AGP at closing, and approximately $139.0 million was to be paid in four quarterly installments beginning December 31, 2014. On December 31, 2014, AGP made its first installment payment of $35.0 million related to its Eagle Ford Acquisition. Prior to the March 31, 2015 installment, the Partnership, AGP, and Cinco amended the purchase and sale agreement to alter the timing and amount of the quarterly payments beginning with the March 31, 2015 payment and ending December 31, 2015, with no change to the overall purchase price. On March 31, 2015, AGP paid $28.3 million and the Partnership issued $20.0 million of its Class D Preferred Units (see Note 12) to satisfy the second installment related to the Eagle Ford Acquisition. On June 30, 2015, AGP paid $16.0 million and the Partnership paid $0.6 million to satisfy the third installment related to the Eagle Ford Acquisition. On July 8, 2015, AGP sold to the Partnership, for a purchase price of $1.4 million, AGP’s interest in a portion of the acreage AGP acquired in the Eagle Ford Acquisition. In September 2015, the Partnership agreed with AGP to have AGP transfer its remaining $36.3 million of deferred purchase obligation, along with the related undeveloped natural gas and oil properties, to the Partnership. On October 1, 2015 the Partnership paid $17.5 million to satisfy the fourth installment related to the Eagle Ford Acquisition. On December 31, 2015 the Partnership paid $21.6 million to satisfy the final installment related to the Eagle Ford Acquisition. The Partnership’s issuance of Class D Preferred Units in March 2015 represented a non-cash transaction for statement of cash flow purposes during the year ended December 31, 2015.

GeoMet Acquisition

On May 12, 2014, the Partnership completed the acquisition of certain assets from GeoMet, Inc. (“GeoMet”) (OTCQB: GMET) for approximately $97.9 million in cash, net of purchase price adjustments, with an effective date of January 1, 2014. The assets included coal-bed methane producing natural gas assets in West Virginia and Virginia.

Norwood Acquisition

On September 20, 2013, the Partnership completed the acquisition of certain assets from Norwood Natural Resources (“Norwood”) for $5.4 million (the “Norwood Acquisition”). The assets acquired included Norwood’s non-operating working interest in certain producing wells in the Barnett Shale. The Norwood Acquisition had an effective date of June 1, 2013.

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment at the dates indicated (in thousands):

	December 31,		Estimated
	2015	2014	Useful Lives in Years
Natural gas and oil properties:			

Proved properties:			
Leasehold interests	$503,586	$441,548	
Pre-development costs	6,014	7,223	
Wells and related equipment	3,076,239	3,026,416	
Total proved properties	3,585,839	3,475,187	
Unproved properties	213,047	217,321	
Support equipment	44,921	37,359	
Total natural gas and oil properties	3,843,807	3,729,867	
Pipelines, processing and compression facilities	56,738	49,547	15 – 20
Rights of way	829	830	20 – 40
Land, buildings and improvements	9,798	9,160	3 – 40
Other	18,405	17,936	3 – 10
	3,929,577	3,807,340	
Less – accumulated depreciation, depletion and amortization	(2,737,966)	(1,543,520)	
	$1,191,611	$2,263,820	

During the year ended December 31, 2015, the Partnership recognized a $1.2 million loss on asset sales and disposals primarily related to a write-down of pipe, pump units and other inventory in New Albany Shale and Black Warrior that are no longer usable and plugging and abandonment costs for certain wells in the New Albany Shale. During the year ended December 31, 2014, the Partnership recognized $1.9 million of loss on asset disposal, primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement. During the year ended December 31, 2013, the Partnership recognized $1.0 million of loss on asset disposal, primarily pertaining to the loss on the sale of its Antrim assets.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. During the year ended December 31, 2015, the Partnership recognized $6.6 million of asset impairments related to its unproved gas and oil properties within property, plant and equipment, net on its consolidated balance sheet, primarily for its unproved acreage in the New Albany Shale. During the year ended December 31, 2013, the Partnership recognized $13.5 million of asset impairments related to its unproved gas and oil properties within property, plant and equipment, net on its consolidated balance sheet, primarily for its unproved acreage in the Chattanooga and New Albany Shales. There were no impairments of unproved gas and oil properties recorded by the Partnership for the year ended December 31, 2014.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Asset impairments and offsetting hedge gains, if any, are included in Asset impairment expense in the Partnership’s consolidated statements of operations. For the year ended December 31, 2015, the Partnership recognized $960.0 million of asset impairment related to proved oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, net of $85.8 million of future hedge gains reclassified from accumulated other comprehensive income. During the year ended December 31, 2014, the Partnership recognized $555.7 million of asset impairment related to proved oil and gas properties within property, plant and equipment, net on its consolidated balance sheet for its Appalachian and mid-continent operations which were impaired due to lower forecasted commodity prices, net of $82.3 million of future hedge gains reclassified from accumulated other comprehensive income. During the year ended December 31, 2013, the Partnership recognized $24.5 million of asset impairments related to its proved gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the New Albany Shale.

During the years ended December 31, 2015, 2014 and 2013, the Partnership recognized $22.6 million, $25.0 million and $26.0 million, respectively, of non-cash property, plant and equipment additions, which were included within the changes in accounts payable and accrued liabilities on the Partnership’s consolidated statements of cash flows.

NOTE 5 – OTHER ASSETS

The following is a summary of other assets at the dates indicated (in thousands):

	December 31,	
	2015	2014

Deferred financing costs, net of accumulated amortization of $36,582 and $18,622, respectively	$50,884	$40,637
Notes receivable	3,708	3,866
Other	5,452	5,578
	$60,044	$50,081

Deferred financing costs are recorded at cost and amortized over the term of the respective debt agreements (see Note 7). Amortization expense of deferred financing costs was $12.4 million, $8.6 million and $6.4 million for the years ended December 31, 2015, 2014 and 2013, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the year ended December 31, 2015, the Partnership recognized $5.6 million for accelerated amortization of deferred financing costs associated with reductions of the borrowing base under the revolving credit facility. During the year ended December 31, 2014, the Partnership recognized $0.6 million for accelerated amortization of deferred financing costs associated with a reduction of the borrowing base under the revolving credit facility. During the year ended December 31, 2013, the Partnership also recognized $3.2 million for accelerated amortization of deferred financing costs associated with the retirement of its then-existing term loan facility and a portion of the outstanding indebtedness under its revolving credit facility with a portion of the proceeds from its issuance of its 7.75% Senior Notes.

At December 31, 2015 and 2014, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership's consolidated balance sheets. The notes have a maturity date of March 31, 2022, and a 2.25% per annum interest rate. The maturity date of the notes can be extended to March 31, 2027, subject to certain conditions, including an extension fee of 1.0% of the outstanding principal balance. For each of the years ended December 31, 2015, 2014 and 2013, $0.1 million of interest income was recognized within other, net on the Partnership's consolidated statements of operations. At December 31, 2015 and 2014, the Partnership recorded no allowance for credit losses within its consolidated balance sheets based upon payment history and ongoing credit evaluations associated with the notes receivable.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

The estimated liability for asset retirement obligations was based on the Partnership's historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements. The liability was discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. The Partnership has no assets legally restricted for purposes of settling asset retirement obligations. Except for its gas and oil properties, the Partnership determined that there were no other material retirement obligations associated with tangible long-lived assets.

The Partnership proportionately consolidates its ownership interest of the asset retirement obligations of its Drilling Partnerships. At December 31, 2015, the Drilling Partnerships had $44.2 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of the Partnership's proportional interest in such liabilities. Under the terms of the respective partnership agreements, the Partnership maintains the right to retain a portion or all of the distributions to the limited partners of its Drilling Partnerships to cover the limited partners' share of the plugging and abandonment costs up to a specified amount per month. As of December 31, 2015, the Partnership has withheld $5.2 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. The Partnership's historical practice and continued intention is to retain distributions from the limited partners as the wells within each Drilling Partnership near the end of their useful life. On a partnership-by-partnership basis, the Partnership assesses its right to withhold amounts related to plugging and abandonment costs based on several factors including commodity price trends, the natural decline in the production of the wells, and current and future costs. Generally, the Partnership's intention is to retain distributions from the limited partners as the fair value of the future cash flows of the limited partners' interest approaches the fair value of the future plugging and abandonment cost. Upon the Partnership's decision to retain all future distributions to the limited partners of its Drilling Partnerships, the Partnership will assume the related asset retirement obligations of the limited partners.

A reconciliation of the Partnership's liability for well plugging and abandonment costs for the periods indicated is as follows (in thousands):

	December 31,		
	2015	2014	2013
Asset retirement obligations, beginning of period	$107,950	$91,179	$64,794
Liabilities incurred	2,070	3,512	6,366
Adjustment to liability due to acquisitions (Note 3)	—	6,997	16,728

Liabilities settled	(2,591)	(1,664)	(1,188)
Accretion expense	6,311	5,747	4,479
Revisions	—	2,179	—
Asset retirement obligations, end of period	$113,740	$107,950	$91,179

The above accretion expense was included in depreciation, depletion and amortization in the Partnership's consolidated statements of operations.

NOTE 7 - DEBT

Total debt consists of the following at the dates indicated (in thousands):

	December 31,	
	2015	2014
Revolving credit facility	$592,000	$696,000
Term loan facility	243,783	—
7.75 % Senior Notes – due 2021	374,619	374,544
9.25 % Senior Notes – due 2021	324,080	323,916
Total debt	1,534,482	1,394,460
Less current maturities	—	—
Total long-term debt	$1,534,482	$1,394,460

Credit Facility

The Partnership is a party to a Second Amended and Restated Credit Agreement, dated July 31, 2013 (as amended from time to time, (the “Credit Agreement”) with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which provides for a senior secured revolving credit facility with a borrowing base of $700.0 million as of December 31, 2015 and a maximum facility amount of $1.5 billion scheduled to mature in July 2018.

On November 23, 2015, the Partnership entered into an Eighth Amendment. Among other things, the Eighth Amendment:

- reduces the borrowing base under the Credit Agreement from $750.0 million to $700.0 million;
- increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- permits the incurrence of third lien debt subject to the satisfaction of certain conditions, including pro forma financial covenant compliance;
- upon the issuance of any third lien debt, reduces the borrowing base by 25% of the stated amount of such third lien debt (other than third lien debt that is used to refinance senior notes, second lien debt and other third lien debt);
- suspends compliance with a maximum ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) until the four fiscal quarter period ending March 31, 2017 and revises the maximum ratio of Total Funded Debt to EBITDA to be 5.75 to 1.00 for the four quarter periods ending March 31, 2017 and June 30, 2017, 5.50 to 1.00 for the four quarter periods ending September 30, 2017 and December 31, 2017, 5.25 to1.00 for the four quarter period ending March 31, 2018, and 5.00 to 1.00 for each four fiscal quarter period ending thereafter;
- replaces the requirement to maintain compliance with a maximum ratio of Senior Secured Total Funded Debt to EBITDA with a requirement to be in compliance with a maximum ratio of First Lien Debt (as defined in the Credit Agreement) to EBITDA of 2.75 to1.00; and
- resets the distribution to $0.15 per common unit and permits increases to the distribution per common unit if (a) the ratio of Total Funded Debt (as of such date) to EBITDA for the most recent four fiscal quarters is equal to or less than 5.00 to1.00 and (b) the borrowing base utilization is less than or equal to 85%, on a pro forma basis after giving effect to the distribution payment.

A Seventh Amendment to the Credit Agreement was entered into on July 24, 2015. Among other things, the Seventh Amendment redefined EBITDA.

A Sixth Amendment to the Credit Agreement was entered into on February 23, 2015. Among other things, the Sixth Amendment:

- reduced the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;
- permitted the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;
- rescheduled the May 1, 2015 borrowing base redetermination to July 1, 2015;
- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increased the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels,

- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and
- revised the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter

The Partnership's borrowing base is scheduled for semi-annual redeterminations in May and November of each year. In February 2015, the borrowing base was reduced from $900 million to $750 million in connection with the Sixth Amendment to the Credit Agreement; in July 2015 (the rescheduled redetermination date in the Sixth Amendment to the Credit Agreement), a determination by the lenders reaffirmed the $750.0 million borrowing base in connection with the Seventh Amendment to the Credit Agreement; and in November 2015, the borrowing base was reduced from $750.0 million to $700.0 million in connection with the Eighth Amendment to the Credit Agreement. The Credit Agreement also provides that the Partnership's borrowing base will be reduced by 25% of the stated amount of any senior notes issued, or additional second lien debt incurred, after July 1, 2015. . In addition, the Credit Agreement provides that our borrowing base will be reduced by 25% of the stated amount of any third lien debt issued (other than third lien debt that is used to refinance senior notes, second lien debt and other third lien debt). At December 31, 2015, $592.0 million was outstanding under the credit facility. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.2 million was outstanding at December 31, 2015. The Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by certain of the Partnership's material subsidiaries, and any non-guarantor subsidiaries of the Partnership are minor. Borrowings under the credit facility bear interest, at the Partnership's election, at either an adjusted LIBOR rate plus an applicable margin between 2.00% and 3.00% per annum (which shall change depending on the borrowing base utilization percentage) or the base rate (which is the higher of the bank's prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.00% per annum (which shall change depending on the borrowing base utilization percentage). The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At December 31, 2015, the weighted average interest rate on outstanding borrowings under the credit facility was 3.25%.

The Credit Agreement contains customary covenants including, without limitation, covenants that limit the Partnership's ability to incur additional indebtedness (but which permits second lien debt in an aggregate principal amount of up to $300.0 million and third lien debt that satisfies certain conditions including pro forma financial covenants), grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidate with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Credit Agreement also requires the Partnership to maintain a ratio of First Lien Debt to EBITDA of 2.75 to 1.00 as set forth in the Eighth Amendment described above, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. The Partnership was in compliance with these covenants as of December 31, 2015. Based on the definitions contained in the Credit Agreement, at December 31, 2015, the Partnership's ratio of current assets to current liabilities was 1.3 to 1.0, and its ratio of First Lien Debt to EBITDA was 2.3 to 1.0.

Although the Partnership currently expects its sources of capital to be sufficient to meet its near-term liquidity needs, there can be no assurance that the lenders under its credit facility will not reduce the borrowing base to an amount below its outstanding borrowings or that its liquidity requirements will continue to be satisfied, given current oil prices and the discretion of its lenders to decrease its borrowing base. Due to the steep decline in commodity prices, the Partnership may not be able to obtain funding in the equity or capital markets on terms it finds acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in some cases, ceased to provide any new funding. If the borrowing base determination in May 2016 results in a borrowing base deficiency and the Partnership cannot access the capital markets and repay debt under its credit facility, the Partnership may be unable to continue to pay distributions to its unitholders and may take other actions to reduce costs and to raise funds to repay debt, such as selling assets or monetizing derivative contracts.

Term Loan Facility

On February 23, 2015, the Partnership entered into a Second Lien Credit Agreement with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the “Term Loan Facility”). The Term Loan Facility matures on February 23, 2020. The Term Loan Facility is presented net of unamortized discount of $6.2 million at December 31, 2015.

The Partnership has the option to prepay the Term Loan Facility at any time, and is required to offer to prepay the Term Loan Facility with 100% of the net cash proceeds from the issuance or incurrence of any debt and 100% of the excess net cash proceeds from certain asset sales and condemnation recoveries. The Partnership is also required to offer to prepay the Term Loan Facility upon the occurrence of a change of control. All prepayments are subject to the following premiums, plus accrued and unpaid interest:

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;
- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

The Partnership's obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of its assets and those of its restricted subsidiaries that guarantee the Partnership's existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by the Partnership's material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at the Partnership's option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the last day of the applicable interest period (or, with respect to interest periods of more than three-months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period) for Eurodollar loans and quarterly for ABR loans. At December 31, 2015, the weighted average interest rate on outstanding borrowings under the term loan facility was 10.0%.

The Second Lien Credit Agreement contains customary covenants including, without limitation, covenants that limit the Partnership's ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in the Partnership's existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. The Partnership was in compliance with these covenants as of December 31, 2015.

Under the Second Lien Credit Agreement, the Partnership may elect to add one or more incremental term loan tranches to the Term Loan Facility so long as the aggregate outstanding principal amount of the Term Loan Facility plus the principal amount of any incremental term loan does not exceed $300.0 million and certain other conditions are adhered to. Any such incremental term loans may not mature on a date earlier than February 23, 2020.

Senior Notes

At December 31, 2015, the Partnership had $374.6 million outstanding of its 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"). The 7.75% Senior Notes were presented net of a $0.4 million unamortized discount as of December 31, 2015. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the Partnership may redeem the 7.75% Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the indenture governing the 7.75% Senior Notes (the "7.75% Senior Notes Indenture")), plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 7.75% Senior Notes.

On December 29, 2015, the Partnership entered into a Third Supplemental Indenture to the 7.75% Senior Notes Indenture following the receipt of requisite consents of the holders of the 7.75% Senior Notes pursuant to a consent solicitation in respect of the 7.75% Senior Notes that commenced on December 10, 2015. As a result of the consent solicitation, the Partnership paid a consent fee of $10.00 for each $1,000 in principal amount of the 7.75% Senior Notes for a total of approximately $3.8 million that was capitalized as deferred financing costs.

Consents were received for the purpose of making the following amendments to the 7.75% Senior Notes Indenture:

(1) Increasing the fixed dollar amount in the basket for secured credit facility indebtedness to $1,000.0 million, the approximate amount of secured credit facility indebtedness currently permitted under the Partnership's secured credit facilities, from $500.0 million. The use of secured indebtedness incurred under such basket in exchange for the 7.75% Senior Notes or the 9.25% Senior Notes (as defined below) will be limited to a maximum amount of $100 million, and the subsidiaries of the Partnership that issued the 7.75% Senior Notes (the "Issuers") will be required to make any offer to exchange the 7.75% Senior Notes for secured indebtedness of the Issuers incurred under such basket to all holders of the 7.75% Senior Notes on a pro rata basis and to make any offer to exchange the 9.25% Senior Notes for secured indebtedness of the Issuers incurred under such basket to all holders of the 9.25% Senior Notes on a pro rata basis.

(2) Adding an additional covenant providing that the Partnership will not permit its consolidated senior secured interest expense to exceed the greater of $80 million in any fiscal year or 8.0% of the consolidated senior secured debt outstanding as of the last day of any fiscal year for which audited financial statements have been provided, subject to certain adjustments and cure rights.

(3) Adding a prohibition with respect to certain make-whole, yield maintenance, redemption, repayment or any other payments, premiums, fees or penalties, providing that such payments or premiums shall not be payable after and during the continuance of an event of default, upon the automatic or other acceleration of such indebtedness prior to its stated maturity date, or after the commencement of a case with respect to the Issuers under bankruptcy law.

At December 31, 2015, the Partnership had $324.1 million outstanding of its 9.25% senior unsecured notes due 2021 ("9.25% Senior Notes"). The 9.25% Senior Notes were presented net of a $0.9 million unamortized discount as of December 31, 2015. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time prior to August 15, 2017, the Partnership may redeem the 9.25% Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the indenture governing the 9.25% Senior Notes (the "9.25% Senior Notes Indenture")), plus accrued and unpaid interest, if any. At any time on or after August 15, 2017, the Partnership may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 9.25% Senior Notes.

On December 17, 2015, the Partnership entered into a Fourth Supplemental Indenture to the 9.25% Senior Notes Indenture following the receipt of requisite consents of the holders of the 9.25% Senior Notes pursuant to a consent solicitation in respect of the 9.25% Senior Notes that commenced on December 10, 2015. As a result of the consent solicitation, the Partnership paid a consent fee of $10.00 for each $1,000 in principal amount of the 9.25% Senior Notes for a total of approximately $3.3 million that was capitalized as deferred financing costs.

Consents were received for the primary purpose of increasing the fixed dollar amount in the basket for secured credit facility indebtedness to $1,050.0 million, the approximate amount of secured credit facility indebtedness currently permitted under the Partnership's secured credit facilities, from $500.0 million. The use of secured indebtedness incurred under such basket in exchange for the 7.75% Senior Notes or the 9.25% Senior Notes will be limited to a maximum amount of $100 million.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of the Partnership's material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several, subject to certain customary automatic release provisions, including, in certain circumstances, the sale or other disposition of all or substantially all the assets of, or all of the equity interests in, the subsidiary guarantor, or the subsidiary guarantor is declared "unrestricted" for covenant purposes, and any subsidiaries of the Partnership, other than the subsidiary guarantors, are minor. There are no restrictions on the Partnership's ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants including, without limitation, covenants that limit the Partnership's ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of the Partnership's assets. The Partnership was in compliance with these covenants as of December 31, 2015.

The aggregate amount of the Partnership's debt maturities is as follows (in thousands):

Years Ended December 31:	
2016	$—
2017	—
2018	592,000
2019	—
2020	250,000
Thereafter	700,000
Total principle maturities	1,542,000
Unamortized premium	309
Unamortized discounts	(7,827)
Total debt	$1,534,482

Total cash payments for interest by the Partnership were $98.5 million $58.7 million and $17.9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

NOTE 8 – DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps, collars and options, in connection with its commodity and interest rate price risk management activities. Management enters into financial instruments to hedge forecasted commodity sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under commodity-based swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. To manage the risk of regional commodity price differences, the Partnership occasionally enters into basis swaps. Basis swaps are contractual arrangements that guarantee a price differential for a commodity from a specified delivery point price and the comparable national exchange price. For natural gas basis swaps, which have negative differentials to the New York Mercantile Stock Exchange ("NYMEX"), the Partnership receives or pays a payment from the counterparty if the price differential to NYMEX is greater or less than the stated terms of the contract. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right, but not the obligation, to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

On January 1, 2015, the Partnership discontinued the use of hedge accounting for its qualified commodity derivatives. As such, changes in fair value of these derivatives after December 31, 2014 are recognized immediately within gain (loss) on mark-to-market derivatives in the Partnership's consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners' capital (deficit) on the Partnership's consolidated balance sheet, are being reclassified to the

Partnership's consolidated statements of operations at the time the originally hedged physical transactions settle.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership's consolidated balance sheets as the initial value of the options. The Partnership recorded net derivative assets of $357.7 million and $274.9 million on its consolidated balance sheets at December 31, 2015 and 2014, respectively. Of the $19.4 million of deferred gains in accumulated other comprehensive income on the Partnership's consolidated balance sheet at December 31, 2015, the Partnership expects to reclassify $16.7 million of gains to its consolidated statement of operations over the next twelve month period as these contracts expire with the remaining gains of $2.7 million being reclassified to the Partnership's consolidated statements of operations in later periods as the remaining contracts expire.

The following table summarizes the commodity derivative activity and presentation in the Partnership's consolidated statement of operations for the year ended December 31, 2015 (in thousands):

	Year Ended December 31, 2015
Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets(1)	$ 86,328
Portion of settlements attributable to subsequent mark to market gains(2)	92,732
Total cash settlements on commodity derivative contracts	$ 179,060
Gains recognized prior to settlement(2)	40,480
Gains recognized on open derivative contracts, net of amounts recognized in income in prior year(2)	226,743
Gains on mark-to-market derivatives	$ 267,223

(1) Recognized in gas and oil production revenue.
(2) Recognized in gain on mark-to-market derivatives.

The Partnership reclassified from accumulated other comprehensive income losses of $7.7 million and gains of $10.2 million for the years ended December 31, 2014 and 2013, respectively, on settled contracts covering commodity production. These gains and loss were included within gas and oil production revenue in the Partnership's consolidated statements of operations. As the underlying prices and terms in the Partnership's derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the years ended December 31, 2014 and 2013 for hedge ineffectiveness.

The following table summarizes the gross fair values of the Partnership's derivative instruments, presenting the impact of offsetting the derivative assets and liabilities included on the Partnership's consolidated balance sheets for the periods indicated (in thousands):

Offsetting Derivatives as of December 31, 2015	Gross Amounts Recognized	Gross Amounts Offset	Net Amount Presented
Current portion of derivative assets	$ 159,460	$ —	$ 159,460
Long-term portion of derivative assets	198,262	—	198,262
Total derivative assets	$ 357,722	$ —	$ 357,722
Current portion of derivative liabilities	$ —	$ —	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ —	$ —	$ —
Offsetting Derivatives as of December 31, 2014			
Current portion of derivative assets	$ 144,357	$ (98)	$ 144,259

Long-term portion of derivative assets	130,972	(370)	130,602
Total derivative assets	$ 275,329	$ (468)	$ 274,861
Current portion of derivative liabilities	$ (98)	$ 98	$ —
Long-term portion of derivative liabilities	(370)	370	—
Total derivative liabilities	$ (468)	$ 468	$ —

The Partnership enters into commodity future option and collar contracts to achieve more predictable cash flows by hedging its exposure to changes in commodity prices. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the physical delivery of the commodity. Crude oil contracts are based on a West Texas Intermediate ("WTI") index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts were recorded at their fair values.

At December 31, 2014, the Partnership had net cash proceeds of $0.2 million, related to its hedging positions monetized on behalf of the Drilling Partnerships' limited partners, which were included within cash and cash equivalents on the Partnership's combined consolidated balance sheet. The Partnership allocated the monetization net proceeds to the Drilling Partnerships' limited partners based on their natural gas and oil production generated over the period of the original derivative contracts during the year ended December 31, 2015.

During the year ended December 31, 2013, the Partnership entered into contracts which provided the option to enter into swap contracts for future production periods ("swaptions") up through September 30, 2013 for production volumes related to assets acquired from EP Energy (see Note 3). In connection with the swaption contracts, the Partnership paid premiums of $14.5 million, which represented their fair value on the date the transactions were initiated and were initially recorded as derivative assets on the Partnership's consolidated balance sheet and was fully amortized as of September 30, 2013. Swaption contract premiums paid are amortized over the period from initiation of the contract through their termination date. For the year ended December 31, 2013, the Partnership recognized $14.5 million, of amortization expense in other, net on the Partnership's consolidated statement of operations related to the swaption contracts.

At December 31, 2015, the Partnership had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset (in thousands)(2)
2016	53,546,300	$ 4.229	$ 92,131
2017	49,920,000	$ 4.219	67,916
2018	40,800,000	$ 4.170	47,153
2019	15,960,000	$ 4.017	13,839
			$ 221,039

Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset (in thousands)(2)
2016	Puts purchased	1,440,000	$ 4.150	$ 2,393
				$ 2,393

Natural Gas Liquids – Crude Fixed Price Swaps

Production Period Ending December 31,	Volumes	Average Fixed Price	Fair Value Asset
	(Bbl)(1)	(per Bbl)(1)	(in thousands)(3)
2016	84,000	$ 85.651	$ 3,651
2017	60,000	$ 83.780	2,124
			$ 5,775

130

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]	Fair Value Asset (in thousands)[3]
2016	1,557,000	$ 81.471	$ 61,284
2017	1,140,000	$ 77.285	33,335
2018	1,080,000	$ 76.281	26,248
2019	540,000	$ 68.371	7,648
			$ 128,515
	Total net assets		$ 357,722

(1) "MMBtu" represents million British Thermal Units; "Bbl" represents barrels; "Gal" represents gallons.
(2) Fair value based on forward NYMEX natural gas prices, as applicable.
(3) Fair value based on forward WTI crude oil prices, as applicable.

In June 2012, the Partnership entered into natural gas put option contracts, which related to future natural gas production of the Drilling Partnerships. Therefore, a portion of any derivative gain or loss is allocable to the limited partners of the Drilling Partnerships based on their share of estimated gas production related to the derivatives not yet settled. At December 31, 2015, net derivative assets of $2.4 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At December 31, 2015, the Partnership had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under its revolving credit facility (see Note 7), the Partnership is required to utilize this secured hedge facility for future commodity risk management activity for its equity production volumes within the participating Drilling Partnerships. Each participating Drilling Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets and by a guarantee of the general partner of the Drilling Partnership. The Partnership, as the ultimate general partner of the Drilling Partnerships, administers the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

NOTE 9 – FAIR VALUE OF FINANCIAL INSTRUMENTS

Management has established a hierarchy to measure the Partnership's financial instruments at fair value, which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 – Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 – Unobservable inputs that reflect the entity's own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership uses a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 8). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership's commodity derivative contracts are valued based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 assets and liabilities within the same class of nature and risk. These derivative instruments are calculated by utilizing commodity indices' quoted prices for futures and options contracts traded on open markets that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Information for assets and liabilities measured at fair value at December 31, 2015 and 2014 was as follows (in thousands):

As of December 31, 2015	Level 1	Level 2	Level 3	Total
Derivative assets, gross				
Commodity swaps	$ —	$355,329	$ —	$355,329
Commodity puts	—	2,393	—	2,393
Total derivative assets, gross	—	357,722	—	357,722
Derivative liabilities, gross				
Commodity swaps	—	—	—	—
Commodity options	—	—	—	—
Total derivative liabilities, gross	—	—	—	—
Total derivatives, fair value, net	$ —	$357,722	$ —	$357,722

As of December 31, 2014	Level 1	Level 2	Level 3	Total
Derivative assets, gross				
Commodity swaps	$ —	$267,242	$ —	$267,242
Commodity puts	—	2,767	—	2,767
Commodity options	—	5,320	—	5,320
Total derivative assets, gross	—	275,329	—	275,329
Derivative liabilities, gross				
Commodity swaps	—	(401)	—	(401)
Commodity options	—	(67)	—	(67)
Total derivative liabilities, gross	—	(468)	—	(468)
Total derivatives, fair value, net	$ —	$274,861	$ —	$274,861

Other Financial Instruments

The estimated fair value of the Partnership’s other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts that the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership’s other current assets and liabilities on its consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair values of the Partnership’s long-term debt at December 31, 2015 and 2014, which consist of its Senior Notes and outstanding borrowings under its revolving credit and term loan facilities (see Note 7), were $907.8 million and $1,219.8 million, respectively, compared with the carrying amounts of $1,534.5 million and $1,394.5 million, respectively. At December 31, 2015 and 2014, the carrying values of outstanding borrowings under the Partnership’s revolving credit facility (see Note 7), which bears interest at variable interest rates, approximated estimated fair values. The estimated fair values of the Partnership’s Senior Notes and the term loan credit facility were based upon the market approach and calculated using yields of the Partnership Senior

Notes and the term loan credit facility as provided by financial institutions and thus were categorized as Level 3 values.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Management estimates the fair value of the Partnership's asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors at the date of establishment of an asset retirement obligation such as: amounts and timing of settlements, the credit-adjusted risk-free rate of the Partnership and estimated inflation rates.

Information for asset retirement obligations that were measured at fair value on a nonrecurring basis for the years ended December 31, 2015 and 2014 were as follows (in thousands):

	Years Ended December 31,	
	2015	2014
	Level 3	Level 3
Asset retirement obligations	$ 2,070	$ 10,509
Total	$ 2,070	$ 10,509

Management estimates the fair value of the Partnership's long-lived assets in connection with reviewing these assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, using estimates, assumptions and judgments regarding such events or circumstances. See Note 4 for a discussion of current year impairments. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

During the year ended December 31, 2014, the Partnership completed the Eagle Ford, Rangely and GeoMet acquisitions (see Note 3). During the year ended December 31, 2013, the Partnership completed the acquisition of certain oil and gas assets from EP Energy (see Note 3).The fair value measurements of assets acquired and liabilities assumed for these acquisitions are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were measured under the Partnership's existing methodology for recognizing an estimated liability for the plugging and abandonment of its gas and oil wells (see Note 6). These inputs required significant judgments and estimates by the Partnership's management at the time of the valuations, which were finalized in 2015.

NOTE 10 — CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with ATLS. The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by employees of ATLS and/or its affiliates. As of December 31, 2015 and 2014, the Partnership had a $1.3 payable and an $8.8 million payable, respectively, to ATLS related to the timing of funding cash accounts, which is recorded in advances from affiliates in the consolidated balance sheets.

Relationship with Drilling Partnerships. The Partnership conducts certain activities through, and a portion of its revenues are attributable to, sponsorship of the Drilling Partnerships. The Partnership serves as general partner and operator of the Drilling Partnerships and assumes customary rights and obligations for the Drilling Partnerships. As the general partner, the Partnership is liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the Drilling Partnerships if it breaches its responsibilities with respect to the operations of the Drilling Partnerships. The Partnership is entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership's revenue and costs and expenses according to the respective partnership agreements.

Relationship with AGP. In connection with the Eagle Ford Acquisition (see Note 3), the Partnership guaranteed the timely payment of the deferred portion of the purchase price that was to be paid by AGP. On September 21, 2015, the Partnership and AGP, in accordance with the terms of the Eagle Ford shared acquisition and operating agreement, agreed that the Partnership would fund the remaining two deferred purchase price installments (see Note 3). In conjunction with this agreement, AGP assigned the Partnership a portion of its non-operating Eagle Ford assets that had a value (as such value was agreed upon by the sellers and the buyers in connection with the Eagle Ford Acquisition) equal to both installments to be paid by the Partnership. As of December 31, 2015 and 2014, the Partnership had an $8.7 million payable and a $6.6 million receivable, respectively, to/from AGP related to the timing of funding cash accounts, which is recorded in advances to/from affiliates in the consolidated balance sheets.

NOTE 11 — COMMITMENTS AND CONTINGENCIES

General Commitments

The Partnership leases office space and equipment under leases with varying expiration dates. Rental expense was $15.7 million, $17.0 million and $13.1 million, for the years ended December 31, 2015, 2014 and 2013, respectively.

Future minimum rental commitments for the next five years are as follows (in thousands):

Years Ended December 31,	
2016	$3,875
2017	3,637
2018	3,261
2019	1,662
2020	1,590
Thereafter	1,849
	$15,874

The Partnership is the ultimate managing general partner of the Drilling Partnerships and has agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. The Partnership has structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, the Partnership is not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and the Partnership may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that it does not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by the Partnership to reflect current well performance, commodity prices and production costs, among other items. Based on its historical experience, as of December 31, 2015, the management of the Partnership believes that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

While its historical structure has varied, the Partnership has generally agreed to subordinate a portion of its share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. The Partnership periodically compares the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, the Partnership recognizes subordination as an estimated reduction of its pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which the Partnership has recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, the Partnership will recognize an estimated increase in its portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized. For the years ended December 31, 2015, 2014 and 2013, $1.7 million, $5.3 million and $9.6 million, respectively, of the Partnership's gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses.

In connection with the Eagle Ford Acquisition (see Note 3), the Partnership guaranteed the timely payment of the deferred portion of the purchase price that was to be paid by AGP. The Partnership's deferred purchase obligation was included within accrued liabilities on the Partnership's consolidated balance sheets at December 31, 2014. In connection with the Eagle Ford Acquisition, the Partnership acquired certain gathering obligations. Estimated fixed and determinable portions of the Partnership's gathering obligations as of December 31, 2015 were as follows: 2016— $0.4 million; 2017 to 2020— none.

In connection with the GeoMet Acquisition (see Note 3), the Partnership acquired certain long-term annual firm transportation obligations. Estimated fixed and determinable portions of the Partnership's firm transportation obligations as of December 31, 2015 were as follows: 2016— $3.7 million; 2017— $2.6 million; 2018— $1.8 million; 2019— $1.8 million; 2020— $1.8 million; thereafter— $4.9 million.

In connection with the Partnership's acquisition of assets from EP Energy E&P Company, L.P. on July 31, 2013 (the "EP Energy Acquisition"), the Partnership acquired certain long-term annual firm transportation obligations. Estimated fixed and determinable portions of the Partnership's firm transportation obligations as of December 31, 2015 were as follows: 2016— $2.2 million; and 2017 to 2020— none.

As of December 31, 2015, the Partnership is committed to expend approximately $7.1 million, principally on drilling and completion expenditures.

Legal Proceedings

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on the Partnership's financial condition or results of operations.

NOTE 12 –ISSUANCES OF UNITS

In August 2015, the Partnership entered into a distribution agreement with MLV & Co. LLC ("MLV") which the Partnership terminated and replaced in November 2015, when the Partnership entered into a distribution agreement (the "Distribution Agreement") with MLV and FBR Capital Markets & Co. ("FBR" and, together with MLV, the "Agents"). Pursuant to the distribution agreement, the Partnership may sell from time to time to or through the Agents the Partnership's 8.625% Class D Cumulative Redeemable Perpetual Preferred Units ("Class D Preferred Units") and Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units") and together with the Class D Preferred Units, the "Preferred Units") having an aggregate offering price of up to $100 million. Sales of Preferred Units, if any, may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act of 1933, as amended, including sales made to or through a market maker other than on an exchange or through an electronic communications network and sales made directly on the New York Stock Exchange, the existing trading market for the Preferred Units. Under the terms of the distribution agreement, the Partnership may sell Preferred Units from time to time to each Agent as principal for its respective account at a price equal to 97.0% of the volume weighted average price of the Class D Preferred Units or Class E Preferred Units, as applicable, on the date of sale. Upon the sale of Preferred Units to an Agent as principal, the Partnership and such Agent will enter into separate terms agreement with respect to such sale.

The Preferred Units may also be offered by the Sales Agent as agents for the Partnership at negotiated prices or prevailing market prices at the time of sale. The Partnership will pay each Agent a commission on Units sold by it in an agency capacity, which shall not be more than 3.0% of the gross sales price of Preferred Units sold through the Agent as agent for the Partnership. Under the August 2015 ATM Agreement, the Partnership issued 90,328 Class D Preferred Units and 1,083 Class E Preferred Units for net proceeds of $0.9 million, net of $0.3 million in commissions and offering expenses paid. Under the November 2015 ATM Agreement, the Partnership did not issue any Class D Preferred Units nor Class E Preferred Units under the preferred equity distribution program, but incurred $0.1 million of net offering expenses.

In July 2015, the remaining 39,654 Class B Preferred Units were converted into common limited partner units.

In May 2015, in connection with the Arkoma Acquisition (see Note 3), the Partnership issued 6,500,000 of its common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.7 million. The Partnership used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under the Partnership's revolving credit facility.

In April 2015, the Partnership issued 255,000 of its Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. The Partnership pays cumulative distributions on a quarterly basis at an annual rate of $2.6875 per unit or at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

In October 2014, the Partnership issued 3,200,000 8.625% Class D Preferred Units at a public offering price of $25.00 per Class D Preferred Unit, yielding net proceeds of approximately $77.3 million from the offering, after deducting underwriting discounts and estimated offering expenses. The Partnership used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition (see Note 3). On March 31, 2015, to partially pay its portion of the quarterly installment related to the Eagle Ford Acquisition, the Partnership issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit. On January 15, 2015, the Partnership paid an initial quarterly distribution of $0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015 (see Note 13). The Partnership pays distributions on a quarterly basis, at an annual rate of $2.15625 per unit, or 8.625% of the $25.00 liquidation preference.

The Class D and Class E Preferred Units rank senior to the Partnership's common units and Class C Preferred Units with respect to the payment of distributions and distributions upon a liquidation event. The Class D and Class E Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change in control. At any time on or after October 15, 2019 for the Class D Preferred Units and April 15, 2020 for the Class E Preferred Units, the Partnership may, at its option, redeem such preferred units in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership may redeem such preferred units following certain changes of control, as described in the respective Certificates of Designation. If the Partnership does not exercise this redemption option upon a change of control, then holders of such preferred units will have the option to convert the preferred units into a number of Partnership common units as set forth in the respective Certificates of Designation. If the Partnership exercises any of its redemption rights relating to the preferred units, the holders of such preferred units will not have the conversion right described above with respect to the preferred units called for redemption. Additionally, if at any time the Partnership's general partner and its affiliates own more than two-thirds of the outstanding class of any limited partner interests, the Partnership's general partner will have the right, which it may assign to any of its affiliates or to the Partnership, to acquire all, but not less than all, of such class of limited partner interests held by at a price equal to the greater of (1) the highest cash price paid by the Partnership's general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which the Partnership's general partner first mails notice of its election to purchase those limited partner interests; and (2) the average of the daily closing prices of the limited partner interests of such class over the 20 trading days preceding the date three days before the date of the mailing of the exercise notice for such call right.

In August 2014, the Partnership entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to the equity distribution agreement, the Partnership may sell from time to time through the Agents common units representing limited partner interests of the Partnership having an aggregate offering price of up to $100.0 million. Sales of common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. The Partnership will pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, the Partnership may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between the Partnership and such Agent. During the year ended December 31, 2015, the Partnership issued 9,803,451 common limited partner units under the equity distribution program for net proceeds of $44.2 million, net of $1.1 million in commissions and offering expenses paid. No units were sold under the equity distribution program during the year ended December 31, 2014.

In May 2014, in connection with the Rangely Acquisition (see Note 3), the Partnership issued 15,525,000 of its common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of $19.90 per unit, yielding net proceeds of approximately $297.3 million.

In March 2014, in connection with the GeoMet Acquisition (see Note 3), the Partnership issued 6,325,000 of its common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of $21.18 per unit, yielding net proceeds of approximately $129.0 million.

In July 2013, in connection with the closing of the EP Energy Acquisition (see Note 3), the Partnership issued 3,749,986 of its newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of $23.10, for proceeds of $86.6 million. The Class C preferred units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act. The Class C preferred units pay cash distributions in an amount equal to the greater of (i) $0.51 per unit and (ii) the distributions payable on each common unit at each declared quarterly distribution date. The Class C preferred units have no voting rights, except as set forth in the certificate of designation for the Class C preferred units, which provides, among other things, that the affirmative vote of 75% of the Class C preferred units is required to repeal such certificate of designation. Holders of the Class C preferred units have the right to convert the Class C preferred units on a one-for-one basis, in whole or in part, into common units at any time before July 31, 2016. Unless previously converted, all Class C preferred units will convert into common units on July 31, 2016. Upon issuance of the Class C preferred units, ATLS, as purchaser of the Class C preferred units, received 562,497 warrants to purchase the Partnership's common units at an exercise price equal to the face value of the Class C preferred units. The warrants were exercisable beginning October 29, 2013 into an equal number of common units of the Partnership at an exercise price of $23.10 per unit, subject to adjustments provided therein. The warrants will expire on July 31, 2016.

Upon issuance of the Class C preferred units and warrants on July 31, 2013, the Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and upon exercise of the warrants. The Partnership agreed to use commercially reasonable efforts to file such registration statement within 90 days of the conversion of the Class C preferred units into common units or the exercise of the warrants. The Partnership filed a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and the registration statement was declared effective on March 27, 2015.

In June 2013, in connection with entering the EP Energy Acquisition (see Note 3), the Partnership sold an aggregate of 14,950,000 of its common limited partner units (including 1,950,000 units pursuant to an over-allotment option) in a public offering at a price of $21.75 per unit, yielding net proceeds of approximately $313.1 million. The Partnership utilized the net proceeds from the sale to repay the outstanding balance under its revolving credit facility (see Note 7).

In May 2013, the Partnership entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution agreement, the Partnership could sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. During the year ended December 31, 2013, the Partnership issued 309,174 common limited partner units under the equity distribution program for net proceeds of $6.9 million, net of $0.4 million in commissions and other offering costs paid. The Partnership utilized the net proceeds from the sale to repay borrowings outstanding under its revolving credit facility. The Partnership terminated this equity distribution agreement effective December 27, 2013.

NOTE 13 – CASH DISTRIBUTIONS

In January 2014, the Partnership's board of directors approved the modification of its cash distribution payment practice to a monthly cash distribution program whereby it distributes all of its available cash (as defined in the partnership agreement) for that month to its unitholders within 45 days from the month end. Prior to that, the Partnership paid quarterly cash distributions within 45 days from the end of each calendar quarter. If the Partnership's common unit distributions in any quarter exceed specified target levels, ATLS will receive between 13% and 48% of such distributions in excess of the specified target levels. While outstanding, the Class B Preferred Units received regular quarterly cash distributions equal to the greater of (i) $0.40 (or $0.1333 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. While outstanding, the Class C Preferred Units will receive regular quarterly cash distributions equal to the greater of (i) $0.51 (or $0.17 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. The Partnership pays quarterly distributions on the Class D Preferred Units at an annual rate of $2.15625 per unit, $0.5390625 per unit paid on a quarterly basis, or 8.625% of the $25.00 liquidation preference. The Partnership pays quarterly distributions on the Class E Preferred Units at an annual rate of $2.6875 per unit, or $0.671875 per unit on a quarterly basis, or 10.75% of the $25.00 liquidation preference.

Distributions declared by the Partnership for the period from January 1, 2013 through December 31, 2015 were as follows (in thousands, except per unit amounts):

Date Cash Distribution Paid	For Month Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners	Total Cash Distribution To Preferred Limited Partners		Total Cash Distribution to the General Partner's Class A Units
May 15, 2013	March 31, 2013	$ 0.5100	$ 22,428	$ 1,957		$ 946
August 14, 2013	June 30, 2013	$ 0.5400	$ 32,097	$ 2,072		$ 1,884
November 14, 2013	September 30, 2013	$ 0.5600	$ 33,291	$ 4,248		$ 2,443
February 14, 2014	December 31, 2013	$ 0.5800	$ 34,489	$ 4,400		$ 2,891
March 17, 2014	January 31, 2014	$ 0.1933	$ 12,718	$ 1,467		$ 1,055
April 14, 2014	February 28, 2014	$ 0.1933	$ 12,719	$ 1,466		$ 1,055
May 15, 2014	March 31, 2014	$ 0.1933	$ 12,719	$ 1,466		$ 1,054
June 13, 2014	April 30, 2014	$ 0.1933	$ 15,752	$ 1,466		$ 1,279
July 15, 2014	May 31, 2014	$ 0.1933	$ 15,752	$ 1,466		$ 1,279
August 14, 2014	June 30, 2014	$ 0.1966	$ 16,029	$ 1,492		$ 1,377
September 12, 2014	July 31, 2014	$ 0.1966	$ 16,028	$ 1,493		$ 1,378
October 15, 2014	August 31, 2014	$ 0.1966	$ 16,032	$ 1,491		$ 1,378
November 14, 2014	September 30, 2014	$ 0.1966	$ 16,032	$ 1,492		$ 1,378
December 15, 2014	October 31, 2014	$ 0.1966	$ 16,033	$ 1,491		$ 1,378
January 14, 2015	November 30, 2014	$ 0.1966	$ 16,779	$ 745	(1)	$ 1,378
February 13, 2015	December 31, 2014	$ 0.1966	$ 16,782	$ 745	(1)	$ 1,378
March 17, 2015	January 31, 2015	$ 0.1083	$ 9,284	$ 643	(1)	$ 203
April 14, 2015	February 28, 2015	$ 0.1083	$ 9,347	$ 643	(1)	$ 204
May 15, 2015	March 31, 2015	$ 0.1083	$ 9,444	$ 643	(1)	$ 206
June 12, 2015	April 30, 2015	$ 0.1083	$ 10,179	$ 642	(1)	$ 221
July 15, 2015	May 31, 2015	$ 0.1083	$ 10,304	$ 643	(1)	$ 223
August 14, 2015	June 30, 2015	$ 0.1083	$ 10,309	$ 637	(2)	$ 223
September 14, 2015	July 31, 2015	$ 0.1083	$ 10,571	$ 638	(2)	$ 229
October 15, 2015	August 31, 2015	$ 0.1083	$ 10,949	$ 637	(2)	$ 236
November 13, 2015	September 30, 2015	$ 0.1083	$ 11,063	$ 637	(2)	$ 239
December 15, 2015	October 31, 2015	$ 0.0125	$ 1,277	$ 637	(2)	$ 39
January 14, 2016	November 30, 2015	$ 0.0125	$ 1,277	$ 638	(2)	$ 39

(1) Includes payments for the Class B and Class C preferred unit monthly distributions.

(2) Includes payments for the Class C preferred unit monthly distributions. The remaining Class B Preferred Units were converted on July 25, 2015, and the Class B Preferred Unitholders received additional ARP common units upon conversion in lieu of the June distribution. No Class B Preferred Units were outstanding at December 31, 2015.

Date Cash Distribution Paid	For the Period	Cash Distribution per Class D Preferred Limited Partner Unit	Total Cash Distribution To Class D Preferred Limited Partners
January 15, 2015	October 2, 2014 – January 14, 2015	$0.616927	$ 1,974
April 15, 2015	January 15, 2015 – April 14, 2015	$0.539063	$ 2,156
July 15, 2015	April 15, 2015 – July 14, 2015	$0.5390625	$ 2,157
October 15, 2015	July 15, 2015 – October 14, 2015	$0.5390625	$ 2,205
January 15, 2016	October 15, 2015 – January 14, 2016	$0.5390625	$ 2,205

Date Cash Distribution Paid	For the Period	Cash Distribution per Class E Preferred Limited Partner Unit	Total Cash Distribution To Class E Preferred Limited Partners
July 15, 2015	April 14, 2015 – July 14, 2015	$ 0.6793	$ 173
October 15, 2015	July 15, 2015 – October 14, 2015	$ 0.671875	$ 172
January 15, 2016	October 15, 2015 – January 14, 2016	$ 0.671875	$ 172

NOTE 14 — BENEFIT PLAN

2012 Long-Term Incentive Plan

The Partnership's 2012 Long-Term Incentive Plan ("2012 LTIP"), effective March 2012, provides incentive awards to officers, employees and directors and employees of the general partner and its affiliates, consultants and joint venture partners (collectively, the "Participants"), who perform services for the Partnership. The 2012 LTIP is administered by the board of the general partner, a committee of the board or the board (or committee of the board) of an affiliate (the "LTIP Committee"). Under the 2012 LTIP, the LTIP Committee may grant awards of phantom units, restricted units or unit options for an aggregate of 2,900,000 common limited partner units. At December 31, 2015, the Partnership had 1,656,630 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 187,633 phantom units, restricted units and unit options available for grant. Share based payments to non-employee directors, which have a cash settlement option, are recognized within liabilities in the consolidated financial statements based upon their current fair market value.

In the case of awards held by eligible employees, following a "change in control", as defined in the 2012 LTIP, upon the eligible employee's termination of employment without "cause", as defined in the 2012 LTIP, or upon any other type of termination specified in the eligible employee's applicable award agreement(s), any unvested award will immediately vest in full and, in the case of options, become exercisable for the one-year period following the date of termination of employment, but in any case not later than the end of the original term of the option. Upon a change in control, all unvested awards held by directors will immediately vest in full.

In connection with a change in control, the LTIP Committee, in its sole and absolute discretion and without obtaining the approval or consent of the unitholders or any Participant, but subject to the terms of any award agreements and employment agreements to which the general partner (or any affiliate) and any Participant are party, may take one or more of the following actions (with discretion to differentiate between individual Participants and awards for any reason):

- cause awards to be assumed or substituted by the surviving entity (or affiliate of such surviving entity);
- accelerate the vesting of awards as of immediately prior to the consummation of the transaction that constitutes the change in control so that awards will vest (and, with respect to options, become exercisable) as to the common units that otherwise would have been unvested so that Participants (as holders of awards granted under the new equity plan) may participate in the transaction;
-

provide for the payment of cash or other consideration to Participants in exchange for the cancellation of outstanding awards (in an amount equal to the fair market value of such cancelled awards);

- terminate all or some awards upon the consummation of the change-in-control transaction, but only if the LTIP Committee provides for full vesting of awards immediately prior to the consummation of such transaction; and
- make such other modifications, adjustments or amendments to outstanding awards or the new equity plan as the LTIP Committee deems necessary or appropriate.

Phantom Units

Phantom units represent rights to receive a common unit, an amount of cash or other securities or property based on the value of a common unit, or a combination of common units and cash or other securities or property upon vesting. Phantom units are subject to terms and conditions determined by the LTIP Committee, which may include vesting restrictions. In tandem with phantom unit grants, the LTIP Committee may grant DERs, which are the right to receive an amount in cash, securities, or other property equal to, and at the same time as, the cash distributions or other distributions of securities or other property made by the Partnership with respect to a common unit during the period that the underlying phantom unit is outstanding. Phantom units granted under the 2012 LTIP generally will vest 25% of the original granted amount on each of the four anniversaries of the date of grant. Of the phantom units outstanding under the 2012 LTIP at December 31, 2015, 159,996 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at December 31, 2015 include DERs. During the years ended December 31, 2015, 2014 and 2013, the Partnership paid $0.7 million, $2.0 million and $1.9 million, respectively, with respect to the 2012 LTIP's DERs. These amounts were recorded as reductions of partners' capital (deficit) on the Partnership's consolidated balance sheets.

The following table sets forth the 2012 LTIP phantom unit activity for the periods indicated:

	Years Ended December 31,					
	2015		2014		2013	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of year	799,192	$ 22.70	839,808	$ 24.31	948,476	$ 24.76
Granted	9,730	8.50	264,173	19.44	145,813	21.87
Vested(1)	(472,278)	23.55	(274,414)	24.46	(215,981)	24.73
Forfeited	(34,539)	23.13	(30,375)	22.76	(38,500)	23.96
Outstanding, end of year(2)(3)	302,105	$ 20.87	799,192	$ 22.70	839,808	$ 24.31
Non-cash compensation expense recognized (in thousands)		$ 4,124		$ 6,367		$ 9,166

(1) The intrinsic values of phantom unit awards vested during the years ended December 31, 2015, 2014 and 2013 were $4.0 million, $5.4 million and $6.1 million, respectively.
(2) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2015 was $0.3 million.
(3) There were approximately $7,000 and $0.1 million recognized as liabilities on the Partnership's consolidated balance sheets at December 31, 2015 and 2014, respectively, representing 13,391 and 26,579 units, respectively, due to the option of the Participants to settle in cash instead of units. The respective weighted average grant date fair values for these units were $13.07 and $21.16 at December 31, 2015 and 2014, respectively.

At December 31, 2015, the Partnership had approximately $1.8 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 1.5 years.

Unit Options

A unit option is the right to purchase a Partnership common unit in the future at a predetermined price (the exercise price). The exercise price of each option is determined by the LTIP Committee and may be equal to or greater than the fair market value of a common unit on the date the option is granted. The LTIP Committee will determine the vesting and exercise restrictions applicable to an award of options, if any, and the method by which the exercise price may be paid by the Participant. Unit option awards expire 10 years from the date of grant. Unit options granted under the 2012 LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. There were 80,038 unit options outstanding under the 2012 LTIP at December 31, 2015 that will vest within the following twelve months. No cash was received from the exercise of options for the years ended December 31, 2015, 2014 and 2013.

The following table sets forth the 2012 LTIP unit option activity for the periods indicated:

	Years Ended December 31,					
	2015		2014		2013	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of year	1,458,300	$ 24.66	1,482,675	$ 24.66	1,515,500	$ 24.68
Granted	—	—	—	—	5,000	21.56
Exercised [1]	—	—	—	—	—	—
Forfeited	(103,775)	24.67	(24,375)	24.52	(37,825)	24.80
Outstanding, end of year[2][3]	1,354,525	$ 24.66	1,458,300	$ 24.66	1,482,675	$ 24.66
Options exercisable, end of year[4]	1,273,487	$ 24.67	730,775	$ 24.67	370,700	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 820		$ 1,700		$ 3,514

(1) No options were exercised during the years ended December 31, 2015, 2014 and 2013.
(2) The weighted average remaining contractual life for outstanding options at December 31, 2015 was 6.4 years.
(3) There were no aggregate intrinsic values of options outstanding at December 31, 2015 and 2014. The aggregate intrinsic value of options outstanding at December 31, 2013 was approximately $1,000.
(4) The weighted average remaining contractual life for exercisable options at December 31, 2015, 2014 and 2013 was 6.4 years, 7.4 years and 8.4 years, respectively. There were no intrinsic values for options exercisable at December 31, 2015, 2014 and 2013.

At December 31, 2015, the Partnership had approximately $44,000 in unrecognized compensation expense related to unvested unit options outstanding under the 2012 LTIP based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 0.4 years. The Partnership used the Black-Scholes option pricing model, which is based on Level 3 inputs, to estimate the weighted average fair value of options granted.

The following weighted average assumptions were used for the options granted during the year ended December 31, 2013:

Expected dividend yield	8.0 %
Expected unit price volatility	35.5%
Risk-free interest rate	1.4 %
Expected term (in years)	6.31
Fair value of unit options granted	$2.95

Restricted Units

Restricted units are actual common units issued to a Participant that are subject to vesting restrictions and evidenced in such manner as the LTIP Committee may deem appropriate, including book-entry registration or issuance of one or more unit certificates. Prior to or upon the grant of an award of restricted units, the LTIP Committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both. A holder of restricted units will have certain rights of holders of common units in general, including the right to vote the restricted units. However, during the period in which the restricted units are subject to vesting restrictions, the holder will not be permitted to sell, assign, transfer, pledge or otherwise encumber the restricted units. There were no restricted units granted, issued or outstanding in 2015, 2014 and 2013.

NOTE 15 – OPERATING SEGMENT INFORMATION

The Partnership's operations include three reportable operating segments. These operating segments reflect the way the Partnership manages its operations and makes business decisions. Operating segment data for the periods indicated were as follows (in thousands):

	Years Ended December 31,		
	2015	2014	2013
Gas and oil production:			
Revenues	$624,222	$472,870	$273,604
Operating costs and expenses	(169,653)	(182,226)	(100,098)
Depreciation, depletion and amortization expense	(145,161)	(229,482)	(132,727)
Asset impairment	(966,635)	(573,774)	(38,014)
Segment income (loss)	$(657,227)	$(512,612)	$2,765
Well construction and completion:			
Revenues	$76,505	$173,564	$167,883
Operating costs and expenses	(66,526)	(150,925)	(145,985)
Segment income	$9,979	$22,639	$21,898
Other partnership management:(1)			
Revenues	$39,306	$55,220	$32,989
Operating costs and expenses	(18,775)	(25,532)	(27,527)
Depreciation, depletion and amortization expense	(12,817)	(10,441)	(7,056)
Segment income (loss)	$7,714	$19,247	$(1,594)
Reconciliation of segment income (loss) to net loss:			
Segment income (loss):			
Gas and oil production	$(657,227)	$(512,612)	$2,765
Well construction and completion	9,979	22,639	21,898
Other partnership management	7,714	19,247	(1,594)
Total segment income (loss)	(639,534)	(470,726)	23,069
General and administrative expenses(2)	(65,968)	(72,349)	(78,063)
Interest expense(2)	(102,133)	(62,144)	(34,324)
Loss on asset sales and disposal(2)	(1,181)	(1,869)	(987)
Net loss	$(808,816)	$(607,088)	$(90,305)
Reconciliation of segment revenues to total revenues:			
Segment revenues:			
Gas and oil production(3)	$624,222	$472,870	$273,604
Well construction and completion	76,505	173,564	167,883
Other partnership management	39,306	55,220	32,989
Total revenues	$740,033	$701,654	$474,476
Capital expenditures:			
Gas and oil production	$111,329	$193,131	$238,291
Other partnership management	14,050	14,202	17,032
Corporate and other	1,759	5,395	8,563
Total capital expenditures	$127,138	$212,728	$263,886

	December 31,	
	2015	2014
Balance sheet:		
Goodwill:		
Gas and oil production	$—	$—
Well construction and completion	6,389	6,389
Other partnership management	7,250	7,250
	$13,639	$13,639
Total assets:		
Gas and oil production	$1,551,450	$2,601,171
Well construction and completion	27,039	39,558
Other partnership management	66,641	65,896
Corporate and other	85,874	91,495
	$1,731,004	$2,798,120

(1) Includes revenues and expenses from well services, gathering and processing, administration and oversight, and other, net that do not meet the quantitative threshold for reporting segment information.
(2) Gain (loss) on asset sales and disposal, general and administrative expenses and interest expense have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented.
(3) Gas and oil production segment revenues include gains on mark to market derivatives.

NOTE 16 — SUBSEQUENT EVENTS

Senior Note Repurchases. In January and February 2016, the Partnership executed transactions to repurchase portions of its senior unsecured notes. Through the end of February 2016, the Partnership has repurchased approximately $20.3 million of its 7.75% Senior Notes due 2021 and approximately $12.1 million of its 9.25% Senior Notes for approximately $5.5 million. As a result of these transactions, the Partnership will recognize approximately $25.9 million as gain on early extinguishment of debt in the first quarter of 2016.

Cash Distributions. On January 28, 2016, the Partnership declared a monthly distribution of $0.0125 per common unit for the month of December 31, 2015. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of limited partner and Class C preferred units, respectively, was paid on February 12, 2016 to unitholders of record at the close of business on February 8, 2016.

On February 24, 2016, the Partnership declared a monthly distribution of $0.0125 per common unit for the month of January 31, 2016. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of limited partner and Class C preferred units, respectively, will be paid on March 16, 2016 to unitholders of record at the close of business on March 9, 2016.

On January 15, 2016, the Partnership paid a quarterly distribution of $0.5390625 per Class D Preferred Unit, or $2.2 million, for the period from October 15, 2015 through January 14, 2016 to Class D Preferred Unitholders of record as of January 4, 2016.

On January 15, 2016, the Partnership paid a quarterly distribution of $0.671875 per Class E Preferred Unit, or $0.2 million, for the period from October 15, 2015 through January 14, 2016 to Class E Preferred Unitholders of record as of January 4, 2016.

NYSE Compliance. On January 12, 2016, the Partnership was notified by the NYSE that it was not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of the common units had been less than $1.00 for 30 consecutive trading days. The Partnership is working to remedy this situation in a timely manner as set forth in the applicable NYSE rules in order to maintain its listing on the NYSE.

NOTE 17 — SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserve Information. The preparation of the Partnership's natural gas, oil and NGL reserve estimates was completed in accordance with its prescribed internal control procedures by its reserve engineers. The reserve information included below was derived from the reserve reports prepared for the Partnership's annual Form 10-K for the years ended December 31, 2015, 2014 and 2013. Other than for the Partnership's Rangely assets, for the periods presented, Wright and Company, Inc., an independent third-party reserve engineer, was retained to prepare a report of proved reserves related to the Partnership. The reserve information for the Partnership includes natural gas, oil and NGL reserves which are all located throughout the United States. The independent reserves engineer's evaluation was based on more than 39 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. For the Partnership's Rangely assets, Cawley, Gillespie, and Associates, Inc. was retained to prepare a report of proved reserves. The independent reserves engineer's evaluation was based on more than 33 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. The Partnership's internal control procedures include verification of input data delivered to its third-party reserve specialist, as well as a multi-functional management review. The preparation of reserve estimates was overseen by its Senior Reserve Engineer, who is a member of the Society of Petroleum Engineers and has more than 17 years of natural gas and oil industry experience. The reserve estimates were reviewed and approved by the Partnership's senior engineering staff and management, with final approval by the President.

The reserve disclosures that follow reflect estimates of proved reserves, proved developed reserves and proved undeveloped reserves, net of royalty interests, of natural gas, crude oil and NGLs owned at year end and changes in proved reserves during the last three years. Proved oil, gas and NGL reserves are those quantities of oil, gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved developed reserves are those reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for undeveloped reserves cannot be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty. The proved reserves quantities and future net cash flows as of December 31, 2015, 2014 and 2013 were estimated using an unweighted 12-month average pricing based on the prices on the first day of each month during the years ended December 31, 2015, 2014 and 2013, including adjustments related to regional price differentials and energy content.

There are numerous uncertainties inherent in estimating quantities of proven reserves and in projecting future net revenues and the timing of development expenditures. The reserve data presented represents estimates only and should not be construed as being exact. In addition, the standardized measures of discounted future net cash flows may not represent the fair market value of oil, gas and NGL reserves included within the Partnership or the present value of future cash flows of equivalent reserves, due to anticipated future changes in oil, gas and NGL prices and in production and development costs and other factors, for their effects have not been proved.

Reserve quantity information and a reconciliation of changes in proved reserve quantities included within the Partnership are as follows (unaudited):

	Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
Balance, January 1, 2013	573,774,257	8,868,836	16,061,897
Extensions, discoveries and other additions(1)	90,098,219	8,255,531	8,197,272
Sales of reserves in-place	(2,755,155)	—	(4,625)
Purchase of reserves in-place(2)	493,232,119	1,942	55,187
Transfers to limited partnerships	(2,485,210)	(239,910)	(258,381)
Revisions(3)	(88,484,468)	(1,412,371)	(3,826,744)
Production	(59,841,724)	(485,226)	(1,267,590)
Balance, December 31, 2013	1,003,538,038	14,988,802	18,957,016
Extensions, discoveries and other additions(1)	58,454,544	3,372,177	3,986,986
Sales of reserves in-place	(169,035)	(1,519)	(11,326)
Purchase of reserves in-place(2)	82,279,988	36,538,935	3,567,531
Transfers to limited partnerships	(4,887,095)	(684,613)	(665,486)
Revisions(3)	3,805,952	(4,941,359)	(2,689,379)
Production	(86,637,612)	(1,254,247)	(1,387,865)
Balance, December 31, 2014	1,056,384,780	48,018,176	21,757,477
Extensions, discoveries and other additions(1)	6,441,969	2,492,424	218,726
Sales of reserves in-place	(2,713,428)	(2,393)	—
Purchase of reserves in-place(2)	3,555,062	8,645,686	653,416
Transfers to limited partnerships	(2,958,882)	(481,771)	(342,156)
Revisions(3)	(377,067,441)	(11,992,308)	(13,382,104)
Production	(79,063,564)	(1,875,654)	(1,055,345)
Balance, December 31, 2015	604,578,496	44,804,160	7,850,014

Proved developed reserves at:			
January 1, 2013	338,655,325	3,400,447	7,884,778
December 31, 2013	766,630,929	3,459,238	7,676,389
December 31, 2014	887,818,577	30,537,868	12,004,774
December 31, 2015	567,992,268	25,484,491	6,334,327

Proved undeveloped reserves at:			
January 1, 2013	235,118,932	5,468,389	8,177,120
December 31, 2013	236,907,109	11,529,564	11,280,627
December 31, 2014	168,566,203	17,480,308	9,752,703
December 31, 2015	36,586,228	19,319,669	1,515,687

(1) For the year ended December 31, 2015, the increase represents PUD conversions related to development activity in the Eagle Ford Shale. For the year ended December 31, 2014, the increase was due to the Rangely, Eagle Ford and Geomet Acquisitions. For the year ended December 31, 2013, the increase was primarily due to the addition of Marble Falls wells.

(2)

Represents purchase of proved reserves in the Rangely, Eagle Ford and GeoMet Acquisitions for the year ended December 31, 2014.

(3) The downward revisions for the year ended December 31, 2015 were primarily due to unfavorable economic conditions primarily related to gas and oil commodity prices. For the year ended December 31, 2014, the downward revision on oil and NGL was primarily due to production underperforming previous year's forecasts. The upward revision for the year ended December 31, 2014 on gas was primarily due to production outperforming previous year's forecast. The downward revisions for the year ended December 31, 2013 were primarily due to a reduction of the Partnership's five year drilling plans in the Barnett Shale and pricing scenario revisions.

145

Capitalized Costs Related to Oil and Gas Producing Activities The components of capitalized costs related to oil and gas producing activities of the Partnership during the periods indicated were as follows (in thousands):

	Years Ended December 31,	
	2015	2014
Natural gas and oil properties:		
Proved properties	$3,585,839	$3,475,186
Unproved properties	213,047	217,322
Support equipment	44,921	37,359
	3,843,807	3,729,867
Accumulated depreciation, depletion and amortization	(2,691,692)	(1,509,509)
Net capitalized costs	$1,152,115	$2,220,358

Results of Operations from Oil and Gas Producing Activities. The results of operations related to the Partnership's oil and gas producing activities during the periods indicated were as follows (in thousands):

	Years Ended December 31,		
	2015	2014	2013
Revenues	$356,999	$470,051	$273,604
Production costs	(169,653)	(182,226)	(100,098)
Depletion	(145,161)	(229,482)	(132,727)
Asset impairment(1)	(966,635)	(573,774)	(38,014)
	$(924,450)	$(515,431)	$2,765

(1) During the year ended December 31, 2015, the Partnership recognized $966.6 million of asset impairment primarily related to oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, and unproved acreage in the New Albany Shale, which were impaired due to lower forecasted commodity prices, net of $85.8 million of future hedge gains reclassified from accumulated other comprehensive income. During the year ended December 31, 2014, the Partnership recognized $573.8 million of asset impairment primarily consisting of $555.7 million related to oil and gas properties within property, plant, and equipment, net on its consolidated balance sheet for its Appalachian and mid-continent operations, which was net of $82.3 million of future hedge gains reclassified from accumulated other comprehensive income, and $18.1 million of goodwill impairment resulting from the decline in overall commodity prices. During the year ended December 31, 2013, the Partnership recognized $38.0 million of impairment primarily related to its shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales.

Costs Incurred in Oil and Gas Producing Activities. The costs incurred by the Partnership in its oil and gas activities during the periods indicated are as follows (in thousands):

	Years Ended December 31,		
	2015	2014	2013
Property acquisition costs:			
Proved properties	$11,513	$699,451	$859,827
Unproved properties	43,820	10,978	895
Exploration costs[1]	1,601	722	1,053
Development costs	73,288	164,853	214,383
Total costs incurred in oil & gas producing activities	$130,222	$876,004	$1,076,158

(1) There were no exploratory wells drilled during the years ended December 31, 2015, 2014 and 2013.

146

Standardized Measure of Discounted Future Cash Flows. The following schedule presents the standardized measure of estimated discounted future net cash flows relating to the Partnership's proved oil and gas reserves. The estimated future production was priced at a twelve-month average for the years ended December 31, 2015, 2014 and 2013, adjusted only for regional price differentials and energy content. The resulting estimated future cash inflows were reduced by estimated future costs to develop and produce the proved reserves based on year-end cost levels and includes the effect on cash flows of settlement of asset retirement obligations on gas and oil properties. The future net cash flows were reduced to present value amounts by applying a 10% discount factor. The standardized measure of future cash flows was prepared using the prevailing economic conditions existing at the dates presented and such conditions continually change. Accordingly, such information should not serve as a basis in making any judgment on the potential value of recoverable reserves or in estimating future results of operations (in thousands):

	Years Ended December 31,		
	2015	2014	2013
Future cash inflows	$3,514,198	$9,317,915	$5,259,688
Future production costs	(1,836,779)	(4,188,364)	(2,393,814)
Future development costs	(1,156,367)	(1,157,305)	(752,349)
Future net cash flows	521,052	3,972,246	2,113,525
Less 10% annual discount for estimated timing of cash flows	(18,283)	(1,987,975)	(1,037,343)
Standardized measure of discounted future net cash flows	$502,769	$1,984,271	$1,076,182

Change in Standardized Discounted Cash Flows. The following table summarizes the changes in the standardized measure of discounted future net cash flows from estimated production of proved oil, gas and NGL reserves (in thousands), including amounts related to asset retirement obligations. Since the Partnership allocates taxable income to its owner, no recognition has been given to income taxes:

	Years Ended December 31,		
	2015	2014	2013
Balance, beginning of year	$1,984,271	$1,076,182	$623,676
Increase (decrease) in discounted future net cash flows:			
Sales of oil and gas produced, net of related costs[1]	(129,352)	(272,961)	(171,300)
Net changes in prices and production costs[2]	(1,453,854)	339,718	85,191
Revisions of previous quantity estimates	(52,775)	4,352	(1,880)
Development costs incurred	58,117	52,077	27,245
Changes in future development costs	(152,305)	(90,887)	(21,579)
Transfers to limited partnerships	(13,291)	(2,966)	(53,392)
Extensions, discoveries, and improved recovery less related costs	13,980	60,832	143,338
Purchases of reserves in-place[3]	53,102	737,101	513,744
Sales of reserves in-place	(2,162)	(332)	(2,053)
Accretion of discount	198,427	107,618	62,368
Estimated settlement of asset retirement obligations	(216)	(16,708)	(18,823)
Estimated proceeds on disposals of well equipment	(1,173)	(21,906)	17,039
Changes in production rates (timing) and other	—	12,151	(127,392)

Outstanding, end of year	$502,769	$1,984,271	$1,076,182

(1) Includes the amount of sales of oil and gas previously included in proved reserves and sold during the period ended.

(2) Decrease due to commodity price declines for the year ended December 31, 2015.

(3) Represents the change in discounted value of the proved reserves primarily due to the purchase of proved reserves due to the Rangely, Eagle Ford and Geomet Acquisitions for the period ended December 31, 2014 and primarily due to the purchase of proved reserves in Marble Falls for the period ended December 31, 2013.

NOTE 18 — QUARTERLY RESULTS (Unaudited)

	Fourth Quarter(1)(2)	Third Quarter(1)(2)	Second Quarter(1)	First Quarter(1)
	(in thousands, except unit data)			
Year ended December 31, 2015:				
Revenues	$142,424	$257,895	$96,125	$243,589
Net loss attributable to common limited partners and the general partner's interests(2)	$(293,013)	$(565,147)	$(51,044)	$83,919
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	$(287,153)	$(553,844)	$(50,023)	$82,240
General partner's interest	(5,860)	(11,303)	(1,021)	1,679
Net loss attributable to common limited partners and the general partner's interests	$(293,013)	(565,147)	$(51,044)	$83,919
Net loss attributable to common unitholders per unit:				
Basic	$(2.81)	$(5.73)	$(0.55)	$0.95
Diluted	$(2.81)	$(5.73)	$(0.55)	$0.93

(1) For the second, third, and fourth quarters of the year ended December 31, 2015, approximately 469,000, 346,000 and 309,000 units, respectively, were excluded from the computation of diluted net income (loss) per common unit, because the inclusion of such units would have been anti-dilutive. For the second, third, and fourth quarters of the year ended December 31, 2015, potential common limited partner units issuable upon conversion of the Partnership's Class B and Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. For the first, second, third and fourth quarters of the year ended December 31, 2015, potential common limited partner units issuable upon exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive.

(2) Includes asset impairment charges of $672.2 million and $294.4 million in the third and fourth quarters of 2015, respectively.

	Fourth Quarter(1)(2)	Third Quarter(1)	Second Quarter(1)	First Quarter(1)
	(in thousands, except unit data)			
Year ended December 31, 2014:				
Revenues	$194,701	$206,699	$138,897	$161,357
Net loss attributable to common limited partners and the general partner's interests(2)	$(585,499)	$(2,590)	$(23,803)	$(14,463)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	$(576,850)	$(5,599)	$(26,203)	$(16,481)

General partner's interest	(8,649)	3,009	2,400	2,018
Net loss attributable to common limited partners and the general partner's interests	$(585,499)	(2,590)	$(23,803)	$(14,463)
Net loss attributable to common unitholders per unit:				
Basic	$(7.04)	$(0.07)	$(0.35)	$(0.27)
Diluted	$(7.04)	$(0.07)	$(0.35)	$(0.27)

(1) For the first, second, third, and fourth quarters of the year ended December 31, 2014, approximately 820,000, 724,000, 797,000, and 791,000 units, respectively, were excluded from the computation of diluted net income (loss) per common unit, because the inclusion of such units would have been anti-dilutive. For the first, second, third, and fourth quarters of the year ended December 31, 2014, potential common limited partner units issuable upon conversion of the Partnership's Class B and Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. For the first, second, third and fourth quarters of the year ended December 31, 2014, potential common limited partner units issuable upon exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive.

(2) Includes an asset impairment charge of $573.8 million in the fourth quarter of 2014.

ITEM 9: CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A: CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2015, our disclosure controls and procedures were effective at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based upon criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the 2013 Internal Control – Integrated Framework (COSO framework).

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods cannot be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.

There have been no changes in our internal control over financial reporting during the fourth quarter of 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Based on our evaluation under the COSO framework, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2015. Grant Thornton LLP, an independent registered public accounting firm, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2015, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Resource Partners, L.P.

We have audited the internal control over financial reporting of Atlas Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (collectively, the "Partnership") as of December 31, 2015, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting ("Management's Report"). Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in the 2013 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2015, and our report dated March 4, 2016 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

March 4, 2016

150

ITEM 9B: OTHER INFORMATION

None.

PART III

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our general partner, Atlas Energy Group, LLC, manages our activities. Unitholders do not directly or indirectly participate in our management or operations, have actual or apparent authority to enter into contracts on our behalf or to otherwise bind us, or elect members of our general partner's board of directors. Our general partner will be liable, as general partner, for all of our debts to the extent not paid, except to the extent that indebtedness or other obligations incurred by us are specifically with recourse only to our assets. Whenever possible, our general partner intends to make our indebtedness or other obligations with recourse only to our assets.

As set forth in our partnership governance guidelines and in accordance with NYSE listing standards, the non-management members of our general partner's board of directors meet in executive session regularly without management. The board member who presides at these meetings rotates each meeting. The purpose of these executive sessions is to promote open and candid discussion among the non-management board members. Interested parties wishing to communicate directly with the non-management members may contact the lead director of our general partner's board of directors, Dennis Holtz. Correspondence to Mr. Holtz should be marked "Confidential" and sent to Mr. Holtz's attention, c/o Atlas Resource Partners, L.P., 1845 Walnut Street, 10th Floor, Philadelphia, Pennsylvania 19103.

The independent board members comprise all of the members of the committees of the board of directors of our general partner: audit committee, compensation committee, nominating and governance committee, investment committee, and environment, health and safety committee. Additionally, independent members of the board of managers of Atlas Resource Partners Holdings, LLC, our wholly-owned subsidiary, comprise all of the members of the conflicts committee.

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management or operation. Rather, personnel employed by Atlas Energy Group manage and operate our business. Some of our officers may spend a substantial amount of time managing the business and affairs of Atlas Energy Group and its affiliates other than us and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

Reimbursement of Expenses of Our General Partner and Its Affiliates

Our general partner does not receive any management fee or other compensation for its services to us apart from its general partner and incentive distributions, when applicable. We reimburse our general partner and its affiliates for all expenses incurred on our behalf. These expenses include the costs of employee, officer and board member compensation and benefits properly allocable to us, and all other expenses necessary or appropriate for the conduct of our business. Our limited partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner as determined by our general partner in its sole discretion, and does not set any aggregate limit on such reimbursements. Our general partner allocates the costs of employee and officer compensation and benefits based upon the amount of business time spent by those employees and officers on our business.

Board of Directors of Our General Partner and our Officers

The following table sets forth information with respect to those persons who serve on the board of directors of our general partner (the "Board") and as our officers:

Name	Age	Position(s)
Edward E. Cohen	77	Executive Chairman
Jonathan Z. Cohen	45	Executive Vice Chairman
Mark C. Biderman	70	Director
DeAnn Craig	64	Director
Dennis A. Holtz	75	Director
Walter C. Jones	53	Director
Jeffrey F. Kupfer	48	Director
Ellen F. Warren	59	Director
Daniel C. Herz	39	Chief Executive Officer
Mark D. Schumacher	53	President
Jeffrey M. Slotterback	33	Chief Financial Officer
Freddie M. Kotek	60	Senior Vice President of Investment Partnership Division
Lisa Washington	48	Vice President, Chief Legal Officer and Secretary
Matthew J. Finkbeiner	36	Chief Accounting Officer
Dave Leopold	52	Chief Operating Officer

Edward E. Cohen has been our Executive Chairman since August 2015 and the Chief Executive Officer and Executive Vice Chairman of our general partner since February 2015. Mr. Cohen served as President of our general partner from February 2015 to April 2015, and before that was Chairman and Chief Executive Officer since February 2012. Mr. Cohen has also served as Chairman of the Board and Chief Executive Officer of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Mr. Cohen was the Chairman of the Board of Atlas Energy's general partner from its formation in January 2006 until February 2011, when he became its Chief Executive Officer and President until February 2015. Mr. Cohen served as the Chief Executive Officer of Atlas Energy's general partner from its formation in January 2006 until February 2009. Mr. Cohen served on the executive committee of Atlas Energy's general partner from 2006 until February 2015. Mr. Cohen also was the Chairman of the Board and Chief Executive Officer of Atlas Energy, Inc. (formerly known as Atlas America, Inc.) from its organization in 2000 until February 2011and also served as its President from September 2000 to October 2009. Mr. Cohen was the Executive Chair of the managing board of Atlas Pipeline Partners GP, LLC ("Atlas Pipeline GP") from its formation in 1999 until February 2015. Mr. Cohen was the Chief Executive Officer of Atlas Pipeline GP from 1999 to January 2009. Mr. Cohen was the Chairman of the Board and Chief Executive Officer of Atlas Energy Resources, LLC and its manager, Atlas Energy Management, Inc. from their formation in June 2006 until February 2011. In addition, Mr. Cohen has been a director of Resource America, Inc. (a publicly-traded specialized asset management company) since 1988 and its Chairman of its Board of Directors since 1990 and was its Chief Executive Officer from 1988 until 2004, and President from 2000 until 2003; Chair of the Board of Resource Capital Corp. (a publicly-traded real estate investment trust) since its formation in 2005 until November 2009 and currently serves on its board; and Chair of the Board of Brandywine Construction & Management, Inc. (a property management company) since 1994. Mr. Cohen is the father of Jonathan Z. Cohen. Mr. Cohen has been active in the energy business for over 30 years. Mr. Cohen's strong financial and energy industry experience, along with his deep knowledge of the company resulting from his long tenure with the company and its predecessors, enables Mr. Cohen to provide valuable perspectives on many issues facing the company. Mr. Cohen's service on the Board of our general partner creates an important link between management and the Board and provides the company with decisive and effective leadership. Mr. Cohen's extensive experience in founding, operating and managing public and private companies of varying size and complexity enables him to provide valuable expertise to the company. Additionally, among the reasons for his appointment as a director, Mr. Cohen brings to the Board the vast experience that he has accumulated through his activities as a financier, investor and operator in various parts of the country. These diverse experiences have enabled Mr. Cohen to bring unique perspectives to the Board, particularly with respect to business management, financial markets and financing transactions and corporate governance issues.

Jonathan Z. Cohen has served as our Executive Vice Chairman since August 2015 and the Executive Chairman of the Board of our general partner since February 2015, and before that was Vice Chairman of our general partner since February 2012. Mr. Cohen has served as the Executive Vice Chairman of the board of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Mr. Cohen served as Executive Chairman of the Board of Atlas Energy's general partner from January 2012 until February 2015. Before that, he served as Chairman of the Board of Atlas Energy's general partner from February 2011 until January 2012 and as Vice Chairman of the Board of its general partner from its formation in January 2006 until February 2011. Mr. Cohen served as chairman of the executive committee of Atlas Energy's general partner from 2006 until February 2015. Mr. Cohen was the Vice Chairman of the Board of Atlas Energy, Inc. from its incorporation in September 2000 until February 2011. Mr. Cohen was the Executive Vice Chair of the managing board of Atlas Pipeline GP from its formation in 1999 until February 2015. Mr. Cohen was the Vice Chairman of the Board of Atlas Energy Resources, LLC and its manager, Atlas Energy Management, Inc. from their formation in June 2006 until February 2011. Mr. Cohen has been a senior officer of Resource America, Inc. (a publicly-traded specialized asset management company) since 1998, serving as the Chief Executive Officer since 2004, President since 2003 and a director since 2002. Mr. Cohen has been Chief Executive Officer, President and a director of Resource Capital Corp. since its formation in 2005. Mr. Cohen is a son of Edward E. Cohen. Mr. Cohen's extensive knowledge of the company resulting from his long length of service with the company and its predecessors, as well as his strong financial and industry experience, allow him to contribute valuable perspectives on many issues facing the company. Mr. Cohen's service on the Board of our general partner creates an important link between management and the Board and provides the company with decisive and effective leadership. Mr. Cohen's involvement with public and private entities of varying size, complexity and focus and raising debt and equity for such entities provides him with extensive experience and contacts that are valuable to the company. Additionally, among the reasons for his appointment as a director, Mr. Cohen's financial, business, operational and energy experience as well as the experience that he has accumulated through his activities as a financier and investor, add strategic vision to our general partner's Board to assist with our growth, operations and development. Mr. Cohen is able to draw upon these diverse experiences to provide guidance and leadership with respect to exploration and production operations, capital markets and corporate finance transactions and corporate governance issues.

Mark C. Biderman has served as a director of our general partner since February 2015. Mr. Biderman served as a director of Atlas Energy's general partner from February 2011 to February 2015. Before that, he was a director of Atlas Energy, Inc. from July 2009 until February 2011. Mr. Biderman was Vice Chair of National Financial Partners Corp. (a publicly-traded financial services company) from September 2008 to December 2008. Before that, from November 1999 to September 2008, he was National Financial's Executive Vice President and Chief Financial Officer. From May 1987 to October 1999, he served as Managing Director and Head of the Financial Institutions Group at CIBC World Markets Group (an investment banking firm) and its predecessor, Oppenheimer & Co., Inc. Mr. Biderman has served as a director and chair of the audit committee of Full Circle Capital Corporation (a publicly-traded investment company), as well as a member of its corporate governance and nominating committee, since August 2010.

Mr. Biderman has served as a director, and chair of the compensation committee of Apollo Commercial Real Estate Finance, Inc. (a publicly-traded commercial real estate finance company) as well as a member of its audit committee, since November 2010. He has also served as a director and chair of the audit committee and as a member of the nominating and corporate governance committee of Apollo Residential Mortgage, Inc. (a publicly-traded residential real estate finance company) since July 2011. Mr. Biderman is a Chartered Financial Analyst. Mr. Biderman brings over 40 years' of business and financial experience to our board of directors, including his service as a chief financial officer for over eight years. Mr. Biderman also brings more than ten years of collective service on various boards of directors as well as his service on the audit committees of four other companies, including our general partner. In addition, our general partner's board of directors benefits from his business acumen and valuable financial experience.

Dolly Ann ("DeAnn") Craig has served as a director of our general partner since March 2012. Dr. Craig served as a consultant to Atlas Energy from April 2011 to January 2012. Dr. Craig has been an Adjunct Professor in the Petroleum Engineering Department of the Colorado School of Mines since January 2009 and a member of the Colorado Oil and Gas Conservation Commission since March 2009. Dr. Craig was the Senior Vice President – Asset Assessment with CNX Gas Corporation from September 2007 until February 2009, and President of Phillips Petroleum Resources (a Canadian subsidiary of Phillips Petroleum) and Manager of Worldwide Drilling and Production of Phillips Petroleum from July 1992 to October 1996. Dr. Craig was a director for Samson Oil & Gas Limited from July 2011 through January 2016 and served as the chair of its audit committee as well as a member of its compensation committee. Dr. Craig is a Past-President of the Society of Petroleum Engineers ("SPE"), Past-President of the Society of Petroleum Engineers' Foundation, and a Past-President of the American Institute of Mining, Metallurgical, and Petroleum Engineers. Dr. Craig was awarded SPE Honorary Membership in 2015, the Society's highest honor. Dr. Craig serves as chair of our general partner's environmental, health and safety committee. Dr. Craig is a member of the National Association of Corporate Directors and is a Registered Professional Engineer in the State of Colorado. Dr. Craig brings to the board of directors of our general partner a strong technical and operational background and practical expertise in issues relating to exploration and production activities. Dr. Craig's experience, particularly her background in petroleum engineering, and her knowledge of our operations resulting from her work as a consultant to us, benefits the Board. In addition, Dr. Craig provides leadership to the board of directors of our general partner with respect to energy policy issues, owing to her experience as a member of the Colorado Oil and Gas Conservation Commission.

Dennis A Holtz has served as a director of our general partner since February 2015 and has served as lead independent director since April 2015. Mr. Holtz served as a director of Atlas Energy's general partner from February 2011 until February 2015. Before that, he was a director of Atlas Energy, Inc. from February 2004 to February 2011. Mr. Holtz maintained a corporate and real estate law practice in Philadelphia and New Jersey from 1988 until his retirement in January 2008. During that period, Mr. Holtz was counsel for or corporate secretary of numerous private and public business entities, and this extensive experience with corporate governance issues was the reason he was chosen as chair of our general partner's nominating and governance committee. As a licensed attorney with over 50 years of business experience, Mr. Holtz offers a unique and invaluable perspective into corporate governance matters. Additionally, Mr. Holtz has extensive knowledge of the energy industry, having served as a director of former affiliated companies for nine years.

Walter C. Jones has served as a director of our general partner since February 2015. Mr. Jones served as a director of Atlas Energy's general partner from October 2013 until February 2015. Since November 2013, Mr. Jones has been the managing director of the Jones Pohl Group, an investment firm based in Dubai, UAE, that invests in clean energy projects, primarily based in developing and developed markets around the globe. JPG is also the majority shareholder of a Dubai-based geothermal energy developer, RG Safa Energy. From April 2010 to October 2013, Mr. Jones served as the U.S. Executive Director and Chief-of-Mission to the African Development Bank in Tunis, Tunisia, having been nominated for the position by President Barack Obama in 2009 and confirmed by the U.S. Senate in 2010. In that position, he represented the United States on the African Development Bank's Board of Directors, and served as chair of the bank's audit committee and vice-chair of both the ethics and development effectiveness committees. From June 2005 until May 2007, Mr. Jones served as the Head of Private Equity and General Counsel at GRAVITAS Capital Advisors, LLC (an independent advisory firm). From May 1994 to May 2005, and then again from September 2007 until April 2010, Mr. Jones was with the Overseas Private Investment Corporation, where he served as Manager for Asia, Africa, the Middle East, Latin America and the Caribbean, as well as a Senior Investment Officer in the Finance Department. Prior to that, Mr. Jones was an International Consultant at the Washington, D.C. firm of Neill & Co. Mr. Jones began his career at the law firm of Sidley & Austin where he was a transactions attorney specializing in leveraged buyouts. Mr. Jones is a seasoned energy company director, having previously served as a director and chair of the audit committee of Atlas Energy Resources, LLC from December 2006 until September 2009 and a director of Atlas Energy, Inc. from September 2009 until March 2010. Mr. Jones' combination of private and public sector experience, as well as his international work, has afforded him a unique combination of management and leadership experience. Our general partner's board of directors also benefits from his investment and transaction expertise as well as his valuable financial experience.

Jeffrey F. Kupfer has served as a director of our general partner since February 2015. Mr. Kupfer served as a director of Atlas Energy's general partner from March 2014 until February 2015. Since October 2009, he has been an Adjunct Professor of Policy and Management at Carnegie Mellon University's H. John Heinz III College. From February 2011 to January 2014, Mr. Kupfer served as a senior advisor for policy and government affairs at Chevron and from September 2009 to February 2011, Mr. Kupfer served as a Senior Vice President at Atlas Energy, Inc. Before that, Mr. Kupfer held a number of high level positions in the U.S. Department of Energy. From March 2008 to January 2009, he was the Acting Deputy Secretary and Chief Operating Officer and from October 2006 to March 2008, he was the Chief of Staff. Mr. Kupfer also worked in the White House as a Special Assistant to the President for Economic Policy in 2006, as the Executive Director of the President's Panel on Federal Tax Reform in 2005, and as Deputy Chief of Staff at the U.S. Treasury Department from 2001 to 2005. Mr. Kupfer brings to the board of directors of our general partner extensive experience in the energy industry, as well his perspective as a former senior official in the U.S. government, which we view as complementary to the industry perspective of other members of the board of directors.

Ellen F. Warren has served as a director of our general partner since February 2015. Ms. Warren served as a director of Atlas Energy's general partner from February 2011 until February 2015. Before that, she was a director of Atlas Energy, Inc. from September 2009 until February 2011. She is founder and President of OutSource Communications, a marketing communications firm that services corporate and nonprofit clients. Prior to founding OutSource Communications in August 2005, she was President of Levy Warren Marketing Media, a public relations and marketing firm she co-founded in March 1998. She was previously Vice President of Marketing/Communications for Jefferson Bank (a Philadelphia-based financial institution) from September 1992 to February 1998, and President of Diversified Advertising, Inc. (an advertising and marketing firm) from December 1984 to September 1992, where she provided marketing services to various industries, including the energy industry. Ms. Warren is a seasoned energy company director who brings her extensive experience as an independent member of the boards of Atlas Energy, Inc., and Atlas Energy Resources, LLC where she chaired a special committee, to our general partner's board of directors. As a member of the National Association of Corporate Directors, Ms. Warren also offers expertise in corporate governance matters. Ms. Warren has 35 years of experience in public relations, corporate communications, crisis communications and marketing, and as the founder and president of various marketing communications firms, she is uniquely positioned to provide leadership to the board of directors in public relations and communications matters. Ms. Warren also brings valuable management, strategic planning, communication, community involvement and leadership skills to our general partner's board of directors.

Daniel C. Herz has served as our Chief Executive Officer since August 2015 and as President of our general partner since April 2015. Mr. Herz has served as President and a director of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Mr. Herz served as Senior Vice President of Corporate Development and Strategy of our general partner from March 2012 to April 2015. Mr. Herz served as Senior Vice President of Corporate Development and Strategy of Atlas Energy's general partner from February 2011 until February 2015. Mr. Herz was Senior Vice President of Corporate Development of Atlas Pipeline Partners GP, LLC from August 2007 until February 2015. He also was Senior Vice President of Corporate Development of Atlas Energy, Inc. and Atlas Energy Resources, LLC from August 2007 until February 2011. Before that, Mr. Herz was Vice President of Corporate Development of Atlas Energy, Inc. and Atlas Pipeline Partners GP, LLC from December 2004 and of Atlas Energy's general partner from January 2006.

Mark D. Schumacher has served as our President since April 2015 and as a Senior Vice President of our general partner since April 2015. Mr. Schumacher served as Chief Operating Officer of our general partner from October 2013 to April 2015. Mr. Schumacher has been the Executive Vice President of Operations of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. He has served as Executive Vice President of Atlas Energy, L.P. from July 2012 to October 2013. From August 2008 to July 2012, Mr. Schumacher served as President of Titan Operating, LLC, which we acquired in July 2012. From November 2006 until August 2008, Mr. Schumacher served as President of Titan Resources, LLC, which built an acreage position in the Barnett Shale that it sold to XTO Energy in October 2008. From February 2005 to November 2006, Mr. Schumacher served as the Team Lead of EnCana Oil & Gas (USA) Inc. where he was responsible for Encana's Barnett Shale development. Mr. Schumacher was an engineer with Union Pacific Resources from 1984 to 2000. Mr. Schumacher has over 29 years of experience in drilling, production and reservoir engineering management, operations and business development in East Texas, Austin Chalk, Barnett Shale, Mid-Continent, the Rockies, the Gulf of Mexico, Latin America and Canada.

Jeffrey M. Slotterback has served as our Chief Financial Officer since September 2015. Mr. Slotterback has served as Chief Financial Officer of our general partner since September 2015 and served as its Chief Accounting Officer from March 2012 to October 2015. Mr. Slotterback has also served as the Chief Financial Officer of the general partner of Atlas Growth Partners, L.P. since September 2015 and served as its Chief Accounting Officer from its inception in 2013 to October 2015. Mr. Slotterback served as Chief Accounting Officer of Atlas Energy's general partner from March 2011 until February 2015. Mr. Slotterback was the Manager of Financial Reporting for Atlas Energy, Inc. from July 2009 until February 2011 and then served as the Manager of Financial Reporting for Atlas Energy GP, LLC from February 2011 until March 2011. Mr. Slotterback served as Manager of Financial Reporting for both Atlas Energy GP, LLC and Atlas Pipeline Partners GP, LLC from May 2007 until July 2009. Mr. Slotterback was a Senior Auditor at Deloitte and Touche, LLP from 2004 until 2007, where he focused on energy and health care clients.
Mr. Slotterback is a Certified Public Accountant.

Freddie M. Kotek has served as our Senior Vice President of the Investment Partnership Division since August 2015 and served as Senior Vice President of Investment Partnership Division of our general partner since March 2012. Mr. Kotek has also served as Executive Vice President and a director of the board of directors of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Mr. Kotek served as Senior Vice President of the Investment Partnership Division of Atlas Energy's general partner from February 2011 until February 2015. Mr. Kotek was an Executive Vice President of Atlas Energy, Inc. from February 2004 until February 2011 and served as a director from September 2001 until February 2004. Mr. Kotek also was Chief Financial Officer of Atlas Energy, Inc. from February 2004 until March 2005. Mr. Kotek has been Chairman of Atlas Resources, LLC since September 2001 and Chief Executive Officer and President since January 2002. Mr. Kotek was a Senior Vice President of Resource America, Inc. from 1995 until May 2004 and President of Resource Leasing, Inc. (a wholly owned subsidiary of Resource America, Inc.) from 1995 until May 2004.

Lisa Washington has been our Vice President, Chief Legal Officer and Secretary since August 2015 and served as Senior Vice President of our general partner since September 2015, Chief Legal Officer and Secretary of our general partner since February 2012 and served as Vice President of our general partner from February 2015 to September 2015. Ms. Washington has served as Chief Legal Officer and Secretary of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy GP, LLC from January 2006 to October 2009, and as a Senior Vice President from October 2008 to October 2009, and as Vice President, Chief Legal Officer and Secretary from February 2011 to February 2015. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Pipeline Partners GP, LLC from November 2005 to October 2009, a Senior Vice President from October 2008 to October 2009 and a Vice President from November 2005 until October 2008. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy, Inc. from November 2005 until February 2011, a Senior Vice President from October 2008 until February 2011, and a Vice President from November 2005 until October 2008. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy Resources, LLC from 2006 until February 2011, a Senior President from July 2008 until February 2011 and a Vice President from 2006 until July 2008. From 1999 to 2005, Ms. Washington was an attorney in the business department of the law firm of Blank Rome LLP.

Matthew Finkbeiner has been our Chief Accounting Officer since October 2015. Mr. Finkbeiner has been the Chief Accounting Officer of our general partner and the general partner of Atlas Growth Partners, L.P. since October 2015. Mr. Finkbeiner has held positions with Deloitte & Touche LLP, including Audit Senior Manager from September 2010 until joining us in October 2015, Audit Manager from September 2007 to September 2010, and Audit Senior/Staff from September 2002 until September 2007. While at Deloitte & Touche LLP, Mr. Finkbeiner managed audits for a diversified base of clients in the oil and gas industry, including master limited partnerships. Mr. Finkbeiner is a Certified Public Accountant.

Dave Leopold has served as our Chief Operating Officer since April 2015. Mr. Leopold previously served as Senior Vice President of Operations from December 2013 until April 2015 and served as Regional Vice President of Operations from March 2013 to December 2013. Mr. Leopold has been the Vice President of Operations of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. From March 2008 to February 2013, Mr. Leopold was the Operations Manager for Chesapeake Energy in Fort Worth, Texas where he led the Barnett Shale operations team to become the second largest producer in the play. From August 2000 to September 2006, Mr. Leopold held various management positions at Anadarko Petroleum Corporation, most recently serving as Production Engineering Manager over the Austin Chalk, Bossier Shale and what is now known as the Eagle Ford Shale. From 1991 to 2000, Mr. Leopold held various engineering and management roles with Union Pacific Resources in Fort Worth, Texas. From 1987 to 1991, he held drilling and reservoir engineering roles with Plains Petroleum Operating Company in Kansas and Colorado.

Our general partner's board of directors is comprised of individuals who bring diverse but complementary skills and experience to oversee our business. Our directors collectively have a strong background in energy, finance, law, accounting and management. Based upon the experience and attributes of the directors discussed herein, our board of our general partner determined that each of the directors should, as of the date hereof, serve on the board of our general partner.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers and board members of our general partner and persons who beneficially own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the Securities and Exchange Commission and to furnish us with copies of all such reports.

Based solely upon our review of reports received by us, or representations from certain reporting persons that no filings were required for those persons, we believe that during fiscal year 2015 our executive officers and our general partner's directors and persons who beneficially owned more than 10% of our common units complied with all applicable filing requirements.

Committees of the Board of Directors of our General Partner

The standing committees of the board of directors of our general partner (the “board”) are the Audit Committee, the Compensation Committee, the Nominating and Governance Committee, the Investment Committee and the Environment, Health and Safety Committee.

Audit Committee. The Audit Committee’s duties include recommending to the board of directors of our general partner the independent public accountants to audit our financial statements and establishing the scope of, and overseeing, the annual audit. The committee also approves any other services provided by public accounting firms. The Audit Committee provides assistance to the board of directors of our general partner in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor’s qualifications and independence and the performance of internal audit function. The Audit Committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that our management and the board of directors of our general partner have established. In doing so, it is the responsibility of the Audit Committee to maintain free and open communication between the committee and the independent auditors, internal accounting function and our management. In accordance with the Sarbanes-Oxley Act of 2002, the Audit Committee has adopted procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, and auditing matters and to allow for the confidential, anonymous submission by employees and others of concerns regarding questionable accounting or auditing matters. All of the members of the Audit Committee meet the independence standards established by the NYSE and the board. The board of directors of our general partner has adopted a written charter for the Audit Committee. The members of the Audit Committee are Mr. Biderman, Mr. Jones and Mr. Kupfer. Mr. Biderman is the chairman and has been determined by the board of directors of our general partner to be an “audit committee financial expert,” as defined by SEC rules. Mr. Biderman serves on the audit committee of more than three public companies. The board of directors of our general partner has determined that Mr. Biderman’s simultaneous service on the audit committees of more than three public companies will not impair his ability to serve effectively on our general partner’s audit committee.

Compensation Committee. The principal functions of the Compensation Committee are to assist the board of directors in carrying out its responsibilities with respect to compensation. The Compensation Committee evaluates the compensation paid or payable to the chief executive officer and our other named executive officers. The Compensation Committee reviews compensation paid or payable under employee qualified benefit plans, employee stock option and restricted stock option plans, under individual employment agreements, and executive compensation and incentive programs. The Compensation Committee has the sole authority to select, retain and/or terminate independent compensation advisors. Ms. Warren and Messrs. Biderman and Holtz are the members of the Compensation Committee, with Ms. Warren serving as the chair. The board of directors has determined that each member of the Compensation Committee is independent, as defined by the rules of the NYSE and in accordance with the independence standards adopted by the board. In addition, the members of the Compensation Committee qualify as “non-employee directors” for purposes of Rule 16b-3 under the Exchange Act.

Nominating and Governance Committee. The principal functions of the Nominating and Governance Committee are to recommend to the board the criteria for members of the board and to identify individuals who meet such criteria, and recommend such individuals to the board for election to fill vacancies on the board of directors of our general partner as well as on the board of managers of Atlas Resource Partners Holdings (“ARP Holdings”); review all compensation paid to directors, in cash or in equity grants, and, on a biannual basis, recommend changes to such compensation, if appropriate; establish procedures for the annual self-assessment by directors set forth by the NYSE, and implement and supervise each self-assessment; and periodically review our formation documents and suggest revisions to them. Ms. Warren and Messrs. Holtz and Kupfer are the members of the Nominating and Governance Committee, with Mr. Holtz acting as the chair. The board of directors of our general partner has determined that each of the members of the Nominating and Governance Committee is independent, as defined by the rules of the NYSE and in accordance with the independence standards adopted by the board.

Investment Committee. The principal functions of the Investment Committee are to assist the board in reviewing management investment practices, policies, strategies, transactions and performance, as well as evaluating and monitoring existing and proposed investments. Messrs. Biderman, W. Jones and Kupfer are the members of the Investment Committee, with Mr. Jones acting as the chair. The board of directors has determined that each of the members of the Investment Committee is independent, as defined by the rules of the NYSE and in accordance with any independence standards adopted by the board.

Environment, Health and Safety Committee. The Environment, Health and Safety Committee assists the board of directors of our general partner in determining whether we have appropriate policies and management systems in place with respect to environment, health and safety and related matters. The committee monitors the adequacy of our policies and management for addressing environment, health and safety matters consistent with prudent exploration and production industry practices. The Environment, Health and Safety Committee monitors and reviews compliance with applicable environment, health and safety laws, rules and regulations. The committee reviews actions taken by management with respect to deficiencies identified or improvements recommended. The members of the Environment, Health and Safety Committee are Dr. Craig, Ms. Warren and Messrs. Holtz and Kupfer. Dr. Craig serves as chair of the committee. The board of directors of our general partner has determined that each of the members of the Environment, Health and Safety Committee is independent, as defined by the rules of the NYSE and in accordance with the independence standards adopted by the board.

Board of Managers of Atlas Resource Partners Holdings, LLC

Atlas Resource Partners Holdings, LLC ("ARP Holdings"), formerly known as Atlas Energy Holdings Operating Company, LLC, is a wholly-owned subsidiary of us. In May 2015, we, as sole member of ARP Holdings, adopted the Amended and Restated Limited Liability Company Agreement of ARP Holdings which provides that ARP Holdings' managerial power and authority be delegated to a board of managers.

The following table sets forth information with respect to those persons who serve as the board of managers of ARP Holdings:

NAME	AGE	POSITION
Edward E. Cohen	77	Chairman
Jonathan Z. Cohen	45	Chief Executive Officer and Manager
Mark D. Schumacher	53	Manager
Daniel C. Herz	39	President and Manager
Carlton M. Arrendell	54	Manager
Jeffrey C. Key	50	Manager
Tony C. Banks	61	Manager

See "– Board of Directors of Our General Partner and our Officers" for biographical information on Messrs. E. Cohen, J. Cohen, Herz and Schumacher".

Carlton M. Arrendell has been a director of ARP Holdings since May 2015. Mr. Arrendell served as a director of Atlas Energy's general partner from February 2011 until the Atlas Energy Merger in February 2015. Before that, he served as a director of Atlas Energy, Inc. from February 2004 until February 2011. Mr. Arrendell has been the Chief Investment Officer and a Vice President of Full Spectrum of NY LLC since May 2007. Before joining Full Spectrum, Mr. Arrendell was a special consultant to the AFL-CIO Investment Trust Corporation following six years of service as Investment Trust Corporation's Chief Investment Officer.

Jeffrey C. Key has been a director of ARP Holdings since May 2015. Mr. Key served as a director of our general partner from February 2012 until the Atlas Energy Merger in February 2015. Mr. Key has been the Managing Partner of his own consulting firm, Key Technology Partners, LLC, which provides strategy development and planning services to communications and networking technology companies since August 2013 and served in the same role from 2002 to 2004. From March 2004 to September 2013, Mr. Key was Vice President, Corporate Development for Tekelec, a supplier of telecommunications equipment. From 2000 to 2002, Mr. Key was a Managing Director of Investment Banking at Bear, Stearns & Co. Inc. Mr. Key served as an independent member of the board of Atlas Energy from 2006 until February 2011.

Tony C. Banks has been a director of ARP Holdings since May 2015. Mr. Banks served on the board of directors of Atlas Pipeline Partners GP, LLC from November 1999 to February 2015. Mr. Banks has been Managing Director of Banks Advisors since December 2015, providing business advisory services to energy and energy technology firms. Prior to December 2015, Mr. Banks was founder, President and Chief Executive Officer from August 2012 to November 2015 of Star Energy Partners, LLC, a retail provider of electricity, natural gas and energy related products and services to residential and business customers in competitive markets throughout the U.S. Prior to that, from February 2011 to August 2012, Mr. Banks was Vice President of Competitive Market Policies of FirstEnergy Solutions Corp., a subsidiary of FirstEnergy Corporation, a public utility, and from October 2009 to February 2011, he served as its Vice President of Product and Market Development. From March 2007 to October 2009, Mr. Banks served as Vice President of Business Development, Performance & Management for FirstEnergy Corporation and from December 2005 to February 2007, Mr. Banks was its Vice President of Business Development. Mr. Banks first joined FirstEnergy Solutions, Corp., in August 2004 as Director of Marketing and in August 2005 became Vice President of Sales & Marketing. Before joining FirstEnergy, Mr. Banks was a consultant to utilities, energy service companies and energy technology firms. From 2000 through 2002, Mr. Banks was President of RAI Ventures, Inc. and Chairman of the board of Optiron Corporation, an energy technology subsidiary of AEI. In addition, Mr. Banks served as President of Atlas Pipeline Partners GP, LLC during 2000 and served as Chief Executive Officer and President of Atlas Energy, Inc. from 1998 through 2000. He also served on the board of directors of TRM Corporation, a provider of ATM services, from October 2006 to April 2008.

Conflicts Committee of Board of Managers of Atlas Resource Partners Holdings, LLC

Since our general partner's board of directors also serves as our board of directors, in order to resolve conflicts of interest, the board amended ARP Holdings' limited liability company agreement to delegate its managerial power and authority with respect to conflicts of interest and/or related party transactions, to a committee comprised of disinterested members of the ARP Holdings board of managers. At such time, the board also amended our related party policy to provide that related party transactions anticipated to exceed $120,000 must be approved, in advance, by the disinterested members of the board of managers of ARP Holdings. The disinterested members of the board of managers constitute the conflicts committee of ARP Holdings. ARP Holdings, following the approval of a related party transaction, is required to notify our general partner's board of directors of such approval and provide the board of directors with a summary of each related party transaction at the next meeting of the board of directors. See "Item 13: Certain Relationships and Related Transactions, and Director Independence." The disinterested members who comprise the conflicts committee of the board of managers of ARP Holdings are Messrs. Arrendell, Banks, and Key with Mr. Banks acting as the chair. Our general partner's board of directors determined that each of the three disinterested members of the board of managers of ARP Holdings, is independent with respect us, as defined by the rules of the New York Stock Exchange and the independence standards adopted by our general partner's board of directors.

Code of Business Conduct and Ethics, Partnership Governance Guidelines and Committee Charters

We have adopted a code of business conduct and ethics that applies to our principal executive officer, principal financial officer and principal accounting officer, as well as to persons performing services for us generally. We have also adopted partnership governance guidelines. Our general partner has adopted charters for the audit committee, compensation committee and environment, health and safety committee. We will make a printed copy of our code of ethics, our partnership governance guidelines and committee charters available to any unitholder who so requests. Requests for print copies may be directed to us as follows: Atlas Resource Partners, L.P., Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275-1011, Attention: Secretary. The code of business conduct and ethics, the partnership governance guidelines and the committee charters are also posted, and any waivers we grant to our code of business conduct and ethics will be posted, on our website at www.atlasresourcepartners.com.

Role in Risk Oversight

General

The role in risk oversight of the board of directors of our general partner recognizes the multifaceted nature of risk management. The board has empowered several of its committees with aspects of risk oversight. We administer our risk oversight function through the Audit Committee, which monitors material enterprise risks, and the Environment, Health and Safety Committee, which assists in determining whether appropriate policies and management systems are in place with respect to environment, health and safety and related matters and monitors and reviews compliance with applicable environmental, health and safety laws, rules and regulations. In order to assist in its oversight function, the Audit Committee oversaw the creation of the enterprise risk management committee consisting of senior officers from our various divisions that are responsible for day-to-day risk oversight. The Audit Committee meets with the members of the enterprise risk management committee as needed to discuss our risk management framework and related areas. It also reviews any major transactions or decisions affecting our risk profile or exposure, and reviews with counsel legal compliance and legal matters that could have a significant impact on our financial statements. The Audit Committee also oversees our internal audit function and is responsible for monitoring the integrity and ensuring the transparency of our financial reporting processes and systems of internal controls regarding finance, accounting and regulatory compliance. The Audit Committee incorporates its risk oversight function into its regular reports to the board of directors of our general partner. The Environment, Health and Safety Committee reviews actions taken by management with respect to deficiencies identified or improvements recommended.

In addition to these committees' role in overseeing risk management, the full board of directors of our general partner regularly engages in discussions of the most significant risks that we face and how these risks are being managed. Our senior executives provide regular updates about our strategies and objectives and the risks inherent within them at board and committee meetings and in regular reports. Board and committee meetings also provide a venue for directors to discuss issues of concern with management. The board and committees may call special meetings when necessary to address specific issues or matters that should be addressed before the next regularly scheduled meeting. In addition, our directors have access to our management at all levels to discuss any matters of interest, including those related to risk. Those members of management most knowledgeable of the issues will attend board meetings to provide additional insight into items being discussed, including risk exposures.

Compensation Programs

Our general partner's compensation policies and programs are intended to encourage those employees who provide services to us to remain focused on both our short-term and long-term goals. Annual incentives are intended to tie a significant portion of each of the named executive officer's compensation to our annual performance and/or that of the divisions for which the officer is responsible. Our Code of Business Conduct and Ethics, which applies to all our officers and our general partner's directors, seeks to mitigate the potential for inappropriate risk taking. We also prohibit hedging transactions involving our units so our officers and our general partner's directors cannot insulate themselves from the effects of our unit price performance.

Atlas Energy Group's compensation committee, together with senior management, also reviews compensation programs and benefits plans affecting employees generally (in addition to those applicable to executive officers who provide services to us), and Atlas Energy Group has concluded that our compensation policies and practices do not create risks that are reasonably likely to have a material adverse effect on the company. Atlas Energy Group also believes that its incentive compensation arrangements provide incentives that do not encourage risk-taking beyond its ability to effectively identify and manage significant risks; are compatible with effective internal controls and its and our risk management practices; and are supported by the oversight and administration of Atlas Energy Group's compensation committee with regard to executive compensation programs.

ITEM 11: EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

For purposes of the following, the individuals listed below are collectively referred to as our, Atlas Energy Group's "Named Executive Officers" or "NEOs." The amounts of their compensation that are allocated to us are disclosed in the tables following this discussion and analysis.

- Daniel C. Herz, our Chief Executive Officer; President of Atlas Energy Group
- Jeffrey M. Slotterback, our Chief Financial Officer; Chief Financial Officer of Atlas Energy Group
- Edward E. Cohen, our Executive Chairman of the Board; Chief Executive Officer of Atlas Energy Group
- Jonathan Z. Cohen, our Executive Vice Chairman of the Board; Executive Chairman of the Board of Atlas Energy Group
- Mark D. Schumacher, our President; Senior Vice President of Atlas Energy Group

The following individuals served as NEOs immediately after the Separation but ceased to be employed by us by the end of 2015:

- Sean P. McGrath, Chief Financial Officer

- Matthew A. Jones, President—ARP

We did not, nor will in the future, directly compensate our NEOs. Because Atlas Energy employed our NEOs, decisions relating to compensation for executive officers in 2014 and prior years were made by the Atlas Energy Compensation Committee. Atlas Energy allocated the compensation of our executive officers between activities on behalf of us and activities on behalf of itself and its other affiliates based upon an estimate of the time spent by such persons on activities for us and for Atlas Energy and its other affiliates.

Following the Separation, in February 2015, Atlas Energy Group formed its Compensation Committee ("Compensation Committee"), comprised solely of Atlas Energy Group independent directors, and became responsible for determining the compensation to be paid to our NEOs pursuant to Atlas Energy Group's compensation objectives and methodology. Atlas Energy Group employs the same allocation process as Atlas Energy employed vis a vis our general partner and us.

The following sections of this Compensation Discussion and Analysis describe the compensation philosophy, policies and practices from and after the February 2015 Separation as they apply to the Named Executive Officers identified above.

Compensation Program Objectives

An understanding of our general partner's executive compensation program begins with the following program objectives:

- Aligning the interests of executives and unitholders. The Compensation Committee seeks to align the interests of our executives with those of our unitholders through equity-based compensation and executive unit ownership requirements.

- Linking rewards to performance. The Compensation Committee seeks to implement a pay-for-performance philosophy by tying a significant portion of executives' compensation to their achievement of goals that are linked to our business strategy and each executive's contributions towards the achievement of those goals.
- Offering competitive compensation. The Compensation Committee seeks to offer an executive compensation program that is competitive and that helps attract, motivate and retain top performing executives.

The Compensation Committee believes that a significant portion of executive compensation should be variable and based on defined performance goals (i.e., "at risk"). The executive compensation program meets this objective by delivering compensation in the form of equity and other performance-based awards.

Governance of Executive Compensation

Compensation Committee

The Compensation Committee was formed at the end of February 2015 following the Separation and is comprised solely of independent directors of the Atlas Energy Group board.

The Compensation Committee is responsible for designing the compensation objectives and methodology, and evaluating the compensation to be paid to our NEOs. The Compensation Committee is also responsible for administering Atlas Energy Group's stock ownership guidelines and certain employee benefit plans, including incentive plans.

Chief Executive Officer

The Atlas Energy Group Chief Executive Officer makes recommendations to the Compensation Committee regarding the salary, bonus and incentive compensation component of each of the other NEO's total compensation. The Atlas Energy Group Chief Executive Officer provides the Compensation Committee with key elements of Atlas Energy Group's and our NEOs' performance during the year or the applicable performance period to assist the committee in its determinations. The Atlas Energy Group Chief Executive Officer, at the Compensation Committee's request, might attend committee meetings to provide insight into our NEOs' performance, as well as the performance of other comparable companies in the same industry. The Compensation Committee determines and approves the Atlas Energy Group Chief Executive Officer's compensation based upon its evaluation of his performance.

Independent Compensation Consultant

For 2015, the Compensation Committee engaged Mercer (US) Inc., a global compensation and benefits consulting firm and wholly-owned subsidiary of Marsh & McLennan Companies, Inc. (“Marsh”), to provide information and objective advice regarding executive compensation. Ultimately, all of the decisions with respect to our NEOs’ compensation are made by the Compensation Committee.

At the request of the Compensation Committee, Mercer worked with Atlas Energy Group’s senior management to develop a peer group in 2015 that reflected, to the greatest extent possible, Atlas Energy Group’s business mix and structure following the Separation. The peer group is comprised of 17 energy companies, nine of which are oil and gas partnerships and eight of which are upstream oil and gas companies. The entire peer group was used to gain broad perspective on compensation for Atlas Energy Group’s and our industry segment using a fairly large data sample, while the nine partnerships (“partnership peers”) allowed the Committee to gain a more focused perspective on compensation at publicly traded partnerships as well.

Immediately following the Separation, the Compensation Committee acknowledged the importance of awarding Atlas Energy Group equity to retain and incentivize the NEOs and other employees. Therefore, it asked Mercer to conduct an analysis with respect to proposed Atlas Energy Group Long-Term Incentive awards, taking into account the value of our long-term incentive awards that had been previously granted. In its analysis, Mercer found that the annualized value of our proposed grants fell below the 25th percentile relative to both peer references. Following receipt of Mercer’s analysis with respect to Atlas Energy Group’s proposed long-term incentives to the NEOs, in June 2015, the Compensation Committee approved the proposed Atlas Energy Group equity grants. See “Determination of 2015 Compensation Amounts—Long-Term Incentives.”

A critical criterion in the Compensation Committee’s selection of Mercer to provide executive and director compensation consulting services was that Mercer does not provide any other executive compensation consulting services to Atlas Energy Group or its affiliated companies, including us, other than insurance brokerage services provided by its parent company, Marsh. Atlas Energy Group, its directors and our executive officers are also required to complete questionnaires on an annual basis, which allows Atlas Energy Group and its subsidiaries, including us, to review whether there are any potential conflicts as a result of personal or business relationships. There were no business or personal relationships between the consultants from Mercer who work with us, Atlas Energy Group's directors and our executive officers other than the executive compensation consulting described herein. The Compensation Committee also determined that the reporting relationship and the compensation of Mercer were separate from, and not determined by reference to Mercer's or Marsh's other lines of business or any other work for Atlas Energy Group and us. Further, the Committee is aware that in the ordinary course of business we, Atlas Energy Group and its affiliates use Marsh's insurance broker services, but it does not monitor or approve those services.

Timing of Compensation Decision Process

Immediately following the Separation, in consultation with the Atlas Energy Group Chief Executive Officer, the Compensation Committee recommended that the base salaries of the NEOs at that time be reduced to reflect the post-Targa transaction company. The Compensation Committee then engaged Mercer to develop a peer group and conduct a competitive analysis with respect to proposed equity grants. See "Governance of Executive Compensation—Independent Compensation Consultant."

Recognizing the importance of retaining executive talent, in consultation with Mercer, the Compensation Committee reviewed and approved employment agreements for Messrs. E. Cohen, J. Cohen, Herz and Schumacher. See "Executive Compensation—Employment Agreements."   The Compensation Committee, with input from management and Mercer, then worked on developing the 2015 performance measurements under the Annual Incentive Plan for Senior Executives (the "Senior Executive Plan").

In January 2016, after the conclusion of the 2015 performance period, the Committee determined the threshold criteria in the performance metrics had been met and approved variable pay awards under the Senior Executive Plan. At the same time, the Compensation Committee made recommendations regarding base pay for the NEOs for 2016.

It is anticipated that before the end of the first quarter of 2016, the Compensation Committee will review and approve a performance formula under the Senior Executive Plan for the 2016 performance period, which is the current year. We anticipate that the Compensation Committee will evaluate 2016 performance and corresponding compensation following the end of 2016.

Elements of Our Compensation Program

Until the closing of the Targa transaction in February 2015, the Atlas Energy Compensation Committee was responsible for making the compensation decisions for the NEOs of Atlas Energy. Additionally, as part of the

Separation, Atlas Energy Group assumed the 401(k) Plan, the Excess 401(k) Plan and the J. Cohen consulting agreement related to Lightfoot. See “Additional Information Concerning Executive Compensation—Consulting Agreement with Mr. J. Cohen.”

Base Salary

Base salary is intended to provide fixed compensation to the NEOs for their performance of core duties that contribute to our success. Base salaries represent one component of our compensation strategy and are not contingent upon the achievement of performance metrics and/or intended to compensate individuals for performance which exceeds expectations.

Annual Incentives

Annual incentives are intended to tie a significant portion of each of the NEO’s compensation to Atlas Energy Group’s annual performance and/or that of its subsidiaries or divisions for which the officer is responsible, including us. Generally, the higher the level of responsibility of the executive within Atlas Energy Group, the greater is the incentive component of that executive’s target total cash compensation. The Compensation Committee may recommend awards of performance-based variable pay and, on rare occasions, discretionary bonuses.

Performance-Based Variable Pay

Atlas Energy Group has an Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, to award variable pay for achievement of predetermined performance measurements during a performance period. Going forward, it is expected that the applicable performance period will be the current fiscal year; however, for 2015, the performance period began at the end of February following the Separation and concluded at the end of 2015. During the 2015 performance period, each of the NEOs participated in the Senior Executive Plan. Awards under the Senior Executive Plan may be paid in cash or in a combination of cash and time-vesting equity.

As soon as was practicable after the Separation, the Compensation Committee approved the performance measurements for the 2015 performance period. The measurements were in the areas of cost control, private channel fund raise, production and environment, health and safety. The Committee determined that, outside of exceptional circumstances, no performance-based variable pay would be made to any NEO unless Atlas Energy Group achieved a minimum threshold of at least three of the six performance measurements during the performance period. Furthermore, since Atlas Energy Group acquired the exploration and production assets through the Separation, the performance measurements involving a 3-year average were based upon the performance results of us, Atlas Energy and/or Atlas Growth Partners:

1. Cost control: The average Eagle Ford Shale Well authorization for expenditure for 2015 must be lower than 85% of the 2014 Average Eagle Ford Shale Well authorization for expenditure;

2. Cost control: Atlas Energy Group's general and administrative expense for 2015 must be lower than the prior 3-year average general and administrative expense;

3. Private Channel Fund Raise Performance: For 2015, Atlas Energy Group must achieve 75% of the prior 3-year average of private channel fund raise;

4. Production Margin Performance: The 2015 value of Atlas Energy Group's hedge positions realized during the year must exceed the prior 3-year average value of commodity hedge positions;

5. Production Margin Performance: Atlas Energy Group's 2015 production gross margin per mcfe must exceed the prior 3-year average production gross margin per mcfe; and

6. Environmental: Atlas Energy Group shall have fewer reportable spills and fewer violations in 2015 than in 2014.

The Compensation Committee determined that if Atlas Energy Group achieved at least three of the six measurements listed above, the Atlas Energy Group NEOs, who are also our NEOs, would be eligible to receive an award paid from a variable pay pool. The maximum amount available to be paid in variable pay is equal to a maximum of 10% of Atlas Energy Group's adjusted net distributable cash flow for the 2015 calendar year period, calculated as the total operating subsidiary distributable cash flow less its general and administrative expense (excluding bonus expense recognized during the period), plus other income, less preferred payments, less stand-alone interest expense. For the purpose of the performance formulas, the operating subsidiary distributable cash flow represents Atlas Energy Group's ownership interest in the distributable cash flow of its operating subsidiaries, regardless of whether such cash was actually distributed.

Pursuant to the Senior Executive Plan, the Compensation Committee had discretion to recommend reductions, but not increases, in the maximum awards. The maximum award allocable to us, expressed as a percentage of Atlas Energy Group's adjusted distributable cash flow for 2015, for each participant was as follows (the percentage represents the portion of the Atlas Energy Group maximum potential award, while the dollar value represents the amount allocable to us): Mr. Herz, 1.70% ($1,120,000); Mr. Slotterback, 0.70% ($490,000); Mr. E. Cohen, 3.20% ($2,170,000); Mr. J. Cohen, 3.20% ($2,170,000); and Mr. Schumacher, 1.20% ($840,000). While the amount of the final maximum variable pay pool allocable to us was $6,790,000, the portion of the actual awards made to the NEOs allocable to us totaled $1,645,000, or approximately 24% of the maximum variable pay pool.

Discretionary Bonuses

In exceptional circumstances, discretionary bonuses could be awarded to recognize individual and group performance without regard to limitations otherwise in effect. The Compensation Committee did not award any discretionary bonuses with respect to our performance for the applicable performance period.

Long-Term Incentives

The Compensation Committee believes that Atlas Energy Group's and our long-term success depends upon aligning its and our executives' and unitholders' interests. To support this objective, Atlas Energy Group provides our executives with the ability to become significant equity holders via awards under the Atlas Resource Partners, L.P. 2012 Long-Term Incentive Plan, which we refer to as our Plan. The Compensation Committee, which administers our Plan, may recommend grants of equity awards in the form of options and/or phantom units. Generally, the unit options and phantom units vest over a three- or four-year period.

Our NEOs also are eligible to receive awards under the Atlas Energy Group 2015 Long-Term Incentive Plan which we refer to as the Atlas Energy Group Plan.

Additional Information Concerning Executive Compensation

Deferred Compensation

All of Atlas Energy Group's employees may participate in its 401(k) plan, which is a qualified defined contribution plan designed to help participating employees accumulate funds for retirement. This plan was originally known as the Atlas Energy 401(k) Plan and was assumed by Atlas Energy Group in connection with the Separation. In February 2015, Atlas Energy Group also assumed the Atlas Energy Executive Excess 401(k) Plan (now known as the "Deferred Compensation Plan"), a nonqualified deferred compensation plan that was designed to permit individuals who exceeded certain income thresholds as established by the IRS and who might be subject to compensation and/or contribution limitations under what was then the Atlas Energy 401(k) plan and is now the Atlas Energy Group 401(k) Plan to defer an additional portion of their compensation. The purpose of the Deferred Compensation Plan is to provide participants with an incentive for a long-term career with Atlas Energy Group by providing them with an appropriate level of replacement income upon retirement. Under the Deferred Compensation Plan, a participant may contribute to an account an amount up to 10% of annual cash compensation (which means a participant's salary and non-performance-based bonus) and up to 100% of all performance-based bonuses. Atlas Energy Group is obligated to make matching contributions on a dollar-for-dollar basis of the amount deferred by the participant subject to a maximum matching contribution equal to 50% of the participant's base salary for any calendar year. Atlas Energy Group does not pay above-market or preferential earnings on deferred compensation. Participation in the Deferred Compensation Plan is available pursuant to the terms of an individual's employment agreement or at the designation of the Compensation Committee. During 2015, Messrs. E. Cohen and J. Cohen were the only participants in the Deferred Compensation Plan. For further details, please see "2015 Nonqualified Deferred Compensation" table. A portion of both the deferred amounts and the matching contributions are allocated to us.

No Hedging of Company Stock

All of Atlas Energy Group's employees are prohibited from hedging their company stock.

No Tax Gross-Ups

Atlas Energy Group does not provide tax reimbursements to our NEOs.

Perquisites

At the discretion of the Compensation Committee, Atlas Energy Group provided perquisites to our NEOs. In 2015, the benefits provided to the NEOs were limited to providing automobile allowances or automobile-related expenses to Messrs. E. Cohen, Herz and Schumacher.

Consulting Agreement with Mr. J. Cohen

We acquired Atlas Energy's direct and indirect ownership interests in the Lightfoot entities as part of the assets and liabilities it acquired in connection with the Targa transaction. As part of the transaction, Atlas Energy Group also assumed the obligations under an agreement pursuant to which Mr. J. Cohen receives compensation in recognition of his role in negotiating and structuring its investment and his continued service as chair of Lightfoot GP. Pursuant to the agreement, Mr. J. Cohen receives an amount equal to 10% of the distributions that Atlas Energy Group receives from the Lightfoot entities, excluding amounts that constitute a return of capital.

Determination of 2015 Compensation Amounts

In January 2016, the Compensation Committee consulted with Mercer, with Atlas Energy Group's Chief Executive Officer participating, to evaluate Atlas Energy Group's and our performance and to approve variable pay awards to NEOs as well as to review base salaries for 2016. At the Committee's request, Mercer provided the Compensation Committee with an analysis of the proposed variable pay awards under the Senior Executive Plan and a benchmark of the proposed NEO base salaries for 2016 relative to the peer group.

Base Salary

Immediately following the Targa merger and Separation, upon recommendation from Atlas Energy Group's Chief Executive Officer, the Compensation Committee approved the reduction of the 2014 base salaries of Messrs. E. Cohen, J. Cohen, Herz and McGrath. The Compensation Committee recognized that Atlas Energy Group's initial size was smaller than its predecessor and approved reductions in the then NEOs base salaries to reflect that fact. During 2015, however, there were management changes that necessitated further adjustments to base salaries.

In January 2016, the Compensation Committee engaged Mercer to conduct an analysis of historical short-term incentives and benchmarking of base salaries of all of the NEOs using the market data from the 2015 market competitive assessment. The Compensation Committee considered the analysis and benchmarking and approved increases to Messrs. E. Cohen and J. Cohen's base salaries not to 2014 levels but to bring their base salaries to the median of the peer group. The Compensation Committee recognized the further increased role that Mr. Herz had undertaken in challenging times and approved an increase in his 2016 base salary to an amount that is competitive with the peer group. The Compensation Committee maintained the base salaries of Messrs. Slotterback and Schumacher at 2015 levels. Mr. Slotterback's base salary was below the median of the peer group and Mr. Schumacher's base salary being competitive with the median.

The amounts reflected in the Summary Compensation Table reflect the amount of each NEOs' base salary that was allocated to us.

Annual Incentives

Variable Pay Awards

After the end of the 2015 fiscal year, the Compensation Committee considered incentive awards pursuant to the Senior Executive Plan based on performance during the 2015 performance period. In determining the actual amounts to be paid to the NEOs, the Compensation Committee considered both individual and company performance. The Atlas Energy Group Chief Executive Officer made recommendations of incentive award amounts based upon Atlas Energy Group's performance as well as the performance of its subsidiaries, including our performance; however, the Compensation Committee had the discretion to approve, reject or modify the recommendations. Further, the Committee had the discretion to reduce, but not increase, the maximum variable pay awards available under the Senior Executive Plan.

In making its determination with respect to variable pay awards to the NEOs, the Compensation Committee found that Atlas Energy Group had achieved all six performance measures set forth in the performance formula. The Compensation Committee took both Atlas Energy Group's overall performance during the year together with the achievement of the performance measurements and, while recognizing the strong performance during challenging times, ultimately awarded variable pay awards that were below the maximum potential awards for each of the NEOs as follows: Mr. E. Cohen, 10% of maximum potential award, Mr. J. Cohen 8% of maximum potential award, Mr. Herz, 63% of maximum potential award, Mr. Schumacher, 42% of maximum potential award; and Mr. Slotterback, 43% of maximum potential award. The amount of the variable pay that was allocated to us was as follows: Mr. Herz—$700,000; Mr. Slotterback—$210,000; Mr. E. Cohen—$210,000; Mr. J. Cohen—$175,000; and Mr. Schumacher—$350,000. The amounts of the maximum potential awards allocable to us were: Mr. Herz—$1,120,000; Mr. Slotterback—$490,000; Mr. E. Cohen—$2,170,000; Mr. J. Cohen—$2,170,000; and Mr. Schumacher—$840,000.

Long-Term Incentives

In an effort to retain the NEOs and all other employees, in June 2015, the Compensation Committee granted Atlas Energy Group phantom units to all of its employees and to the NEOs as follows: Mr. Herz—250,000 phantom units; Mr. Slotterback—35,000 phantom units; Mr. E. Cohen—250,000 phantom units; Mr. J. Cohen—250,000 phantom units; Mr. Schumacher—175,000 phantom units; and Mr. McGrath—175,000. Mr. McGrath forfeited the award upon his departure. These awards are to vest one-third on each anniversary of the grant. The Compensation Committee recognized that such continuity grants were critical to retention of executive and other employees even in a "soft" energy market.

SUMMARY COMPENSATION TABLE

Name and principal position	Year	Salary ($)	Bonus ($)	Unit awards ($)(1)	Option awards ($)	Non-equity incentive plan compensation ($)(2)	All other compensation ($)		Total ($)
Daniel C. Herz, Chief Executive Officer	2015	227,500	—	1,607,500	—	700,000	143,195	(3)	2,678,195
	2014	120,000	225,000	4,869,769	—	—	509,621		5,724,390
	2013	105,000	225,000	499,973	—	—	396,113		1,226,086
Jeffrey M. Slotterback, Chief Financial Officer	2015	143,769	—	225,050	—	210,000	11,315	(4)	590,135
Sean P. McGrath, Chief Financial Officer(10)	2015	183,413	—	1,125,250	—	—	78,244	(5)	1,386,907
	2014	180,000	—	3,411,694	—	270,000	236,718		4,098,412
	2013	157,500	—	499,973	—	270,000	159,851		1,087,324
Edward E. Cohen, Executive Chairman of the Board	2015	332,500	—	1,607,500	—	210,000	715,799	(6)	2,865,799
	2014	380,000	—	15,583,198	—	760,000	1,815,584		18,538,782
	2013	380,000	—	1,799,988	—	456,000	1,027,426		3,663,414
Jonathan Z. Cohen, Executive Vice Chairman of the Board	2015	292,115	—	1,607,500	—	175,000	780,869	(7)	2,855,485
	2014	266,000	—	15,083,221	—	760,000	1,591,764		17,700,985
	2013	266,000	—	1,599,968	—	456,000	922,444		3,244,412
Mark D. Schumacher, President	2015	262,500	—	1,125,250	—	350,000	127,833	(8)	1,865,583
Matthew A. Jones, President—ARP(11)	2015	93,087	—	—	—	—	148,616	(9)	241,702
	2014	320,000	—	4,945,806	—	600,000	591,211		6,457,017
	2013	320,000	—	1,099,995	—	600,000	479,010		2,499,005

(1) For fiscal year 2015, the amounts reflect the grant date fair value of the phantom units under the Atlas Energy Group Plan. The grant date fair value was determined in accordance with FASB ASC Topic 718 and is based on

the market value on the grant date of Atlas Energy Group units (June 2015). See "Compensation Discussion & Analysis—Determination of 2015 Compensation Amounts—Long-Term Incentives." For fiscal year 2014, the amounts reflect the grant date fair value of the phantom units under the Atlas Energy Plan. The grant date fair value was determined in accordance with FASB ASC Topic 718 and is based on the market value on the grant date of Atlas Energy units (February 2014 and June 2014). For fiscal year 2013, unit awards include bonus payments attributable to 2013 performance and continuity grants. ATLS grants in fiscal year 2013 were awarded as part of the bonus process. For fiscal year 2013, the amounts reflect the grant date fair value of the phantom units under the Atlas Energy Plan.

(2) Amounts in this column reflect variable pay awards made under the Senior Executive Plan.

(3) Comprised of (i) payments on DERs of $13,762 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $122,713 with respect to the phantom units awarded under the Atlas Energy Plans; and (iii) our allocated portion of an automobile allowance.

(4) Comprised of (i) payments on DERs of $3,148 with respect to the phantom units awarded under our Plan and (ii) payments on DERs of $8,168 with respect to the phantom units awarded under the Atlas Energy Plans.

(5) Comprised of (i) payments on DERs of $23,368 with respect to the phantom units awarded under our Plan and (ii) payments on DERs of $54,876 with respect to the phantom units awarded under the Atlas Energy Plans.

(6) Comprised of (i) payments on DERs of $29,490 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $317,237 with respect to the phantom units awarded under the Atlas Energy Plans, (iii) our allocated portion of the matching contribution of $367,096 under the Atlas Energy Deferred Compensation Plan, and (iv) our allocated portion of tax, title and insurance premiums for Mr. E. Cohen's automobile.

(7) Comprised of (i) payments on DERs of $29,490 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $289,181 with respect to the phantom units awarded under the Atlas Energy Plans, (iii) our allocated portion of the matching contribution of $262,904 under the Atlas Energy Deferred Compensation Plan, and (iv) our allocated portion of $199,295 paid under the agreement relating to Lightfoot.

(8) Comprised of (i) payments on DERs of $96,255 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $24,858 with respect to the phantom units awarded under the Atlas Energy Plans; and (iii) our allocated portion of an automobile allowance.
(9) Comprised of (i) payments on DERs of $19,660 with respect to the phantom units awarded under our Plan; (ii) payments on DERs of $126,549 with respect to the phantom units awarded under the Atlas Energy Plans; and (iii) our allocated portion of an automobile allowance.
(10) We announced in August 2015 that Mr. McGrath resigned from his position as Chief Financial Officer.
(11) We announced in April 2015 that Mr. Jones retired from his position as President—ARP.

2015 Grants of Plan-Based Awards

Name	Estimated possible payments under non-equity incentive plan awards[1] Threshold ($)	Target ($)	Maximum ($)	Grant date	All other stock awards: Number of units	All other option awards: Number of securities underlying options	Exercise or base price of option awards ($/Unit)	Grant date fair value of unit and option awards ($)[3]
Daniel C. Herz	--	--	1,600,000	6/8/15	250,000[2]	—	—	1,607,500
Jeffrey M. Slotterback	--	--	700,000	6/8/15	35,000 [2]	—	—	225,050
Sean P. McGrath	--	--	--	6/8/15	175,000[2]	—	—	1,125,250
Edward E. Cohen	--	--	3,100,000	6/8/15	250,000[2]	—	—	1,607,500
Jonathan Z. Cohen	--	--	3,100,000	6/8/15	250,000[2]	—	—	1,607,500
Mark D. Schumacher	--	--	1,200,000	6/8/15	175,000[2]	—	—	1,125,250
Matthew A. Jones	--	--	--	--	--	--	--	--

(1) Represents performance-based variable pay under the Senior Executive Plan that may be paid in cash and/or equity. As discussed under “Compensation Discussion and Analysis—Elements of our Compensation Program—Annual Incentives” and “—Performance-Based Bonuses,” the Compensation Committee set performance goals based on the distributable cash flow and average production volumes, and established maximum awards, but not minimum or target amounts, for each eligible NEO.
(2) Represents phantom units granted under Atlas Energy Group’s 2015 Long-Term Incentive Plan.
(3) The grant date fair value was calculated in accordance with FASB ASC Topic 718.

Employment Agreements and Potential Payments Upon Termination or Change of Control

Atlas Energy Group has employment agreements with certain of our NEOs that provide for severance compensation to be paid if their employment is terminated under certain conditions.

Terms Used

"Good reason" is defined in Mr. E. Cohen's and Mr. J. Cohen's employment agreements as:

- a material reduction in base salary;
- a demotion from his position;
- a material reduction in duties, it being deemed such a material reduction if we cease to be a public company unless we become a subsidiary of a public company and,
- in the case of Mr. E. Cohen, he becomes the chief executive officer of the public parent immediately following the applicable transaction;
- in the case of Mr. J. Cohen, he becomes the executive chairman of the board of directors of the public parent immediately following the applicable transaction;

- failure to be elected to our board; or
- any material breach of the agreement by us.

"Good reason" is defined in Messrs. Herz's and Schumacher's employment agreements as:

- a material reduction in base salary;
- a demotion from his position and,
- in the case of Mr. Herz, it being deemed such a demotion if we or a successor entity ceases to be a public company;
- a material reduction in duties and
    - in the case of Mr. Herz, it being deemed such a material reduction if the executive is not an officer of any successor entity with the same or greater responsibilities as his current position;
- a requirement of the executive to relocate to a location more than 35 miles from the executive's previous location;
- any material breach of the agreement.

"Cause" is defined in Mr. E. Cohen's and Mr. J. Cohen's employment agreements as:

- the executive is convicted of a felony, or any crime involving fraud or embezzlement;
- the executive intentionally and continually fails to perform his reasonably assigned duties (other than as a result of incapacity due to physical or mental illness), which failure was materially and demonstrably detrimental to us and continues for 30 days after written notice signed by a majority of our independent directors is delivered to the executive; or
- the executive is determined, through arbitration, to have materially breached the restrictive covenants in the agreement.

“Cause” is defined in Messrs. Herz’s and Schumacher’s employment agreements as:

- the executive commits any demonstrable and material act of fraud;
- illegal or gross misconduct that is willful and resulted in damage to our business or reputation;
- the executive is convicted of a felony or any crime involving fraud or embezzlement;
- failure to substantially perform his duties (other than as a result of physical or mental illness or injury) after written demand and a reasonable opportunity to cure; or
- failure to follow reasonable written instructions which are consistent with his duties and not in violation of any applicable law.

Daniel C. Herz

Effective September 4, 2015, we and Atlas Energy Group entered into an employment agreement with Mr. Herz to secure his service as our Chief Executive Officer and as the President of Atlas Energy Group. The agreement has an initial term of two years, however, beginning on the first anniversary of the agreement, the term will automatically renew daily so that on any day the agreement shall have a then-remaining term of not less than one year, provided that such automatic extension shall cease upon our written notice of our election to terminate the agreement at the end of the one-year period then in effect.

The agreement provides for an annual base salary of $350,000, which can be increased by our board in its discretion, but cannot be decreased after any such increase. Mr. Herz is entitled to receive a bonus determined in accordance with procedures established by our board or its compensation committee. Mr. Herz is eligible to receive grants of equity-based compensation as determined by our board or its compensation committee, and is entitled to participate in all applicable incentive, savings, retirement programs and health and welfare plans to the same extent as our other senior officers, directors or executives, and to receive reimbursement of work-related administrative and travel expenses.

The agreement provides the following benefits in the event of a termination of employment:

- Upon a termination by us for cause or by Mr. Herz without good reason, he is entitled to receive payment of accrued but unpaid base salary and (to the extent required to be paid under company policy) amounts of accrued but unpaid vacation, in each case through the date of termination.

- Upon a termination of employment due to death or disability (defined as Mr. Herz being physically or mentally disabled for more than 180 days in the aggregate or 90 consecutive days during any 365-day period and the board’s determination, in good faith based upon medical evidence, that he is unable to perform his duties and services), all equity awards held by Mr. Herz would accelerate and vest in full upon such termination, and in the case of options to purchase equity, such options will become immediately exercisable and remain in effect and exercisable through their respective terms (“Acceleration of Equity Vesting”), and Mr. Herz or his estate is entitled to receive (i) any portion of his base salary that has been earned but unpaid through the date of termination and (to the extent required to be paid under company policy) amounts of accrued but unpaid vacation through the date of termination, (ii) any accrued but unpaid cash incentive compensation earned for any year prior to the year in which the termination occurs, and (iii) an amount representing the cash incentive compensation opportunity awarded to Mr. Herz for the year in which the termination occurs, equal to the cash incentive compensation earned by Mr. Herz for the prior fiscal year multiplied by a fraction, the numerator of which was the number of days in the fiscal year in which the termination occurs through the date of termination, and the denominator of which was the total number of days in such fiscal year (the “Pro-Rata Bonus”) ((i), (ii) and (iii) are collectively referred to as the “Accrued Obligations”). In addition, Mr. Herz (in the case of disability) and his dependents are entitled to company-paid health insurance for the one-year period after termination.

- Upon a termination of employment by us without cause (which includes non-renewal of the agreement) or by the executive for good reason, Mr. Herz is entitled to either: (i) if Mr. Herz did not timely execute (or revoked) a release of claims against us, payment of the Accrued Obligations and any other benefits accrued and due under any of our applicable benefit plans and programs; or (ii) in addition to (i) above, if Mr. Herz timely executes and does not revoke a release of claims against us: (A) severance compensation in an amount equal to two times his annual compensation (which is defined generally as the sum of (1) his annualized base salary in effect immediately before the termination of employment plus (2) the average of the bonuses earned for the three years preceding the year in which the termination occurs); (B) at our request, two years of COBRA coverage, the premium of which shall be paid by Mr. Herz and reimbursed by us, such reimbursement amount reduced by the amount that Mr. Herz would be required to contribute for health and dental coverage if he continued as an active employee (or, where such coverage would have a negative tax effect to our healthcare plan or Mr. Herz, we can elect to pay Mr. Herz cash in lieu of such coverage at COBRA rates); and Acceleration of Equity Vesting.

In connection with a change of control, any “excess parachute payments” (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Herz would be reduced if and to the extent he would be in a better after-tax position as a result of such reduction.

The following table provides an estimate of the value of the benefits to Mr. Herz if a termination event had occurred as of December 31, 2015.

Reason for termination	Lump sum severance payment	Benefits[1]	Accelerated vesting of unit awards and option awards[2]
Death	$932,918	$ 17,110	$ 237,500
Disability	932,918	17,110	237,500
Termination by us without cause or by Mr. Herz for good reason	2,355,836[3]	34,220	237,500

(1) Dental and medical benefits were calculated using 2015 COBRA rates allocated to us.

(2) Represents the value of unvested unit awards disclosed in the "2015 Outstanding Equity Awards at Fiscal Year-End" table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2015.

(3) Represents allocation to us of two times (a) Mr. Herz's base salary plus (b) incentive compensation from Atlas Energy in respect of fiscal year 2014.

Edward E. Cohen

Effective September 4, 2015, we and Atlas Energy Group entered into an employment agreement with Mr. Cohen to secure his service as Atlas Energy Group's Chief Executive Officer. The agreement has a term of three years, which automatically renews daily unless terminated before the expiration of the term pursuant to the termination provisions of the agreement.

The agreement provides for an annual base salary of $350,000, which can be increased at the discretion of our board's compensation committee pursuant to its normal performance review policies for senior level executives, but cannot be decreased. Mr. Cohen is entitled to receive cash and non-cash bonus compensation in such amounts as our board or its compensation committee may approve or under the terms of any incentive plan that we maintain for our senior level executives. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs provided by us for our senior level executives generally, at levels commensurate with the benefits provided to other senior executives and with adjustments appropriate for Mr. Cohen's position. Mr. Cohen is also entitled to participate in all employee welfare benefit plans and programs or executive perquisites made available to our senior level executives as a group or to our employees generally, as well as the reimbursement of reasonable expenses related to Mr. Cohen's employment. We are required to maintain a term life insurance policy on Mr. Cohen's life that provides a death benefit of $3 million to one or more beneficiaries designated by Mr. Cohen, which such policy, at his request, can be assumed by Mr. Cohen upon a termination of employment, if and as allowed by the applicable insurance company.

The agreement provides the following benefits in the event of a termination of employment:

- Upon termination of employment due to death, all equity awards held by Mr. Cohen will accelerate and vest in full upon the later of the termination of employment or six months after the date of grant of the awards ("Acceleration of Equity Vesting"), and Mr. Cohen's estate is entitled to receive, in addition to payment of all accrued and unpaid amounts of base salary, cash incentive compensation earned for any year prior to the year in which the termination occurs, vacation and business expenses ("Accrued Obligations"), and a prorated annual bonus for the year of termination, which shall be no less than the amount of the cash incentive compensation awarded in respect of the prior fiscal year, if any, prorated for the number of days in the current year prior to such termination (the "Pro Rata Bonus").

- We may terminate Mr. Cohen's employment if he were unable to perform the material duties of his employment for 180 days in any 12-month period because of physical or mental injury or illness which constitutes a disability for purposes of Section 409A of the Internal Revenue Code of 1986, as amended, but we are required to pay his base salary until we act to terminate his employment. Upon termination of employment due to disability, Mr. Cohen would receive the Accrued Obligations, all amounts payable under our long-term disability plans, if any, three years' continuation of group term life and health insurance benefits for himself and, where applicable, his spouse and dependents (or, alternatively, we can elect to pay Mr. Cohen cash in lieu of such coverage in an amount equal to three years' healthcare coverage at COBRA rates and the premiums we would have paid during the three-year period for such life insurance) (such coverage, the "Continued Benefits"), Acceleration of Equity Vesting and the Pro Rata Bonus.

- Upon termination of employment by us without cause or by Mr. Cohen for good reason, Mr. Cohen is entitled to either (i) if he does not execute and does not revoke a release of claims against us and related parties, payment of the Accrued Obligations, or (ii) in addition to payment of the Accrued Obligations, if he executes and does not revoke a release of claims against us and related parties, (A) a lump sum cash payment in an amount equal to three times his average compensation (which is defined generally as the sum of (1) his annualized base salary in effect immediately before the termination of employment plus (2) the average of the bonuses earned for the three years preceding the year in which the termination occurs), (B) Continued Benefits for three years, (C) the Pro Rata Bonus, and (D) Acceleration of Equity Vesting.

- Upon a termination of employment by us for cause or by Mr. Cohen without good reason, he is entitled to receive payment of the Accrued Obligations and any accrued benefits.

In connection with a change of control, any "excess parachute payments" (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Cohen would, if agreed to by Mr. Cohen, be reduced if and to the extent he would be in a better after-tax position as a result of such reduction.

The following table provides an estimate of the value of the benefits to Mr. Cohen if a termination event had occurred as of December 31, 2015.

Reason for termination	Lump sum severance payment	Benefits[1]	Accelerated vesting of unit awards and option awards[2]
Death	$4,533,698 [3]	$	$ 237,500
Disability	2,433,698	39,749	237,500
Termination by us without cause or by Mr. Cohen for good reason	11,834,794 [4]	39,749	$ 237,500

(1) Dental and medical benefits were calculated using 2015 COBRA rates allocated to us.
(2) Represents the value of unvested unit awards disclosed in the “2015 Outstanding Equity Awards at Fiscal Year-End” table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2015.
(3) Represents pro rata variable incentive pay and life insurance policy proceeds allocated to us.
(4) Represents allocation to us of pro rata incentive compensation from Atlas Energy in respect of fiscal year 2014 plus three times (a) Mr. Cohen’s base salary plus (b) incentive compensation from Atlas Energy in respect of fiscal year 2014.

Jonathan Z. Cohen

Effective September 4, 2015, we and Atlas Energy Group entered into an employment agreement with Mr. Cohen to secure his service as Executive Chairman of Atlas Energy Group’s board of directors. The agreement has a term of three years, which automatically renews daily unless terminated before the expiration of the term pursuant to the termination provisions of the agreement.

The agreement provides for an annual base salary of $350,000, which can be increased at the discretion of our board’s compensation committee pursuant to its normal performance review policies for senior level executives, but cannot be decreased. Mr. Cohen is entitled to receive cash and non-cash bonus compensation in such amounts as our board or its compensation committee may approve or under the terms of any incentive plan that we maintain for our senior level executives. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs provided by us for our senior level executives generally, at levels commensurate with the benefits provided to other senior executives and with adjustments appropriate for Mr. Cohen’s position. Mr. Cohen is also entitled to participate in all employee welfare benefit plans and programs or executive perquisites made available to our senior level executives as a group or to our employees generally, as well as the reimbursement of reasonable expenses related to Mr. Cohen’s employment. We are required to maintain a term life insurance policy on Mr. Cohen’s life that provides a death benefit of $3 million to one or more beneficiaries designated by Mr. Cohen, which such policy, at his request, can be assumed by Mr. Cohen upon a termination of employment, if and as allowed by the applicable insurance company.

The agreement provides the same benefits in the event of a termination of employment as described above in Mr. E. Cohen's employment agreement summary.

In connection with a change of control, any "excess parachute payments" (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Cohen would, if agreed to by Mr. Cohen, be reduced if and to the extent he would be in a better after-tax position as a result of such reduction.

The following table provides an estimate of the value of the benefits to Mr. Cohen if a termination event had occurred as of December 31, 2015.

Reason for termination	Lump sum severance payment	Benefits[1]	Accelerated vesting of unit awards and option awards[2]
Death	$4,533,698 [3]	$	$ 237,500
Disability	2,433,698	58,296	237,500
Termination by us without cause or by Mr. Cohen for good reason	11,204,794 [4]	58,296	237,500

(1) Dental and medical benefits were calculated using 2015 COBRA rates allocated to us.
(2) Represents the value of unvested unit awards disclosed in the "2015 Outstanding Equity Awards at Fiscal Year-End" table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2015.
(3) Represents pro rata variable incentive pay and life insurance policy proceeds allocated to us.

(4) Represents allocation to us of pro rata incentive compensation from Atlas Energy in respect of fiscal year 2014 plus three times (a) Mr. Cohen's base salary plus (b) incentive compensation from Atlas Energy in respect of fiscal year 2014.

Mark D. Schumacher

Effective September 4, 2015, we and Atlas Energy Group entered into an employment agreement with Mr. Schumacher to secure his service as our President and Atlas Energy Group's Senior Vice President. The agreement has an initial term of two years, however, beginning on the first anniversary of the agreement, the term will automatically renew daily so that on any day the agreement shall have a then-remaining term of not less than one year, provided that such automatic extension shall cease upon our written notice of our election to terminate the agreement at the end of the one-year period then in effect.

The agreement provides for an annual base salary of $375,000, which can be increased by us, but cannot be decreased after any such increase. Mr. Schumacher is entitled to receive a bonus determined in accordance with procedures established by our board or its compensation committee. Mr. Schumacher is eligible to receive grants of equity-based compensation as determined by our board or its compensation committee, and is entitled to participate in all applicable incentive, savings, retirement programs and health and welfare plans to the same extent as our other senior officers, directors or executives, and to receive reimbursement of work-related administrative and travel expenses.

The agreement provides the same benefits in the event of a termination of employment as described above in Mr. Herz's employment agreement summary.

In connection with a change of control, any "excess parachute payments" (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Schumacher would be reduced if and to the extent he would be in a better after-tax position as a result of such reduction.

The following table provides an estimate of the value of the benefits to Mr. Schumacher if a termination event had occurred as of December 31, 2015:

Reason for termination	Lump sum severance payment	Benefits[1]	Accelerated vesting of unit awards and option

			awards[2]
Death	$ 183,750	$ 12,613	$ $220,325
Disability	183,750	12,613	220,325
Termination by us without cause or by Mr. Schumacher for good reason	892,500 [3]	$ 25,227	220,325

[1] Dental and medical benefits were calculated using 2015 COBRA rates.

[2] Represents the value of unvested unit awards disclosed in the "2015 Outstanding Equity Awards at Fiscal Year-End" table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2015.

[3] Represents two times (a) Mr. Schumacher's base salary plus (b) incentive compensation from Atlas Energy in respect of fiscal year 2014.

Long-Term Incentive Plans

Our Plan

Our 2012 Long-Term Incentive Plan provides equity incentive awards to officers, employees and board members of our general partner and employees of our affiliates, consultants and joint venture partners who perform services for us. Our Plan is administered by the Atlas Energy Compensation Committee which may grant awards of either phantom units, unit options or restricted units for an aggregate of 2,900,000of our common limited partner units.

Phantom Units. A phantom unit entitles a participant to receive a common unit upon vesting of the phantom unit. The phantom units generally vest over four years. In tandem with phantom unit grants, the Compensation Committee may grant a right to receive an amount in cash equal to, and at the same time as, the cash distributions on our common units (“DERs”). The Compensation Committee determines the vesting period for phantom units.

Unit Options. A unit option entitles a participant to receive a common unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option may be equal to or more than the fair market value of a common unit as determined by the Compensation Committee on the date of grant of the option. The Compensation Committee determines the vesting and exercise period for unit options.

Restricted Units. A restricted unit is an outstanding common unit of ours that entitles a participant to receive the unit, free from restrictions, upon vesting of the restricted unit. Prior to or upon grant of an award of restricted units, the Atlas Energy Compensation Committee can condition the vesting or transferability of the restricted units upon conditions that it may determine such as the attainment of performance goals.

Change of Control.

Individual	Triggering event	Acceleration
Eligible employees	Change of Control (as defined in our Plan), and Termination of employment without “cause” as defined in our Plan or upon any other type of termination specified in the applicable award agreement(s), following a change of control	Unvested awards immediately vest in full and in the case of options, become exercisable for the one-year period following the date of termination (but not later than the end of the original term of the option)
	Change of Control (as defined in our Plan)	Unvested awards immediately vest in full

Independent
directors

Atlas Energy Group 2015 Long-Term Incentive Plan

In February 2015, the Atlas Energy Group board of directors adopted the Atlas Energy Group, LLC 2015 Long-Term Incentive Plan, which we refer to as the “Atlas Energy Group Plan.” It provides equity incentive awards to officers, employees and board members of Atlas Energy Group, employees of its affiliates, consultants and joint-venture partners who performed services for it, including for us. The Atlas Energy Group Plan is administered by the Atlas Energy Group Compensation Committee which can grant awards of either phantom units, unit options or restricted units for an aggregate of 5,250,000 common units.

Phantom Units. A phantom unit entitles a participant to receive a common unit or cash or other securities or property based on the value of a common unit. In tandem with phantom unit grants, the committee may grant a DER. The committee will determine the vesting period for phantom units.

Options. An option entitles a participant to receive a common unit upon payment of the exercise price for the option after completion of vesting of the option. The exercise price of the option may be equal to or more than the fair market value of a common unit as determined by the committee on the date of grant of the option. The committee will determine the vesting and exercise period for options, and the method by which payment of the exercise price may be made.

Restricted Units. A restricted unit is an outstanding common unit issued that entitles a participant to receive the unit, free from restrictions, upon vesting of the restricted unit. Prior to or upon grant of an award of restricted units, the committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both.

Change of Control.

Individual	Triggering event	Acceleration
Eligible employees	Change of Control (as defined in the Atlas Energy Group LTIP), and	Unvested awards immediately vest in full and in the case of options, become exercisable for the one-year period following the date of termination (but not later than the end of the original term of the option)
	Termination of employment without "cause" as defined in the Atlas Energy Group LTIP or upon any other type of termination specified in the applicable award agreement(s), following a change of control	
Independent directors	Change of Control (as defined in the Atlas Energy Group LTIP)	Unvested awards immediately vest in full

2015 OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option awards				Unit awards	
Name	Exercisable	Unexercisable	Option exercise price ($)	Option expiration date	Number of units that have not vested(#)	Market value of units that have not vested($)
Daniel C. Herz	100,000 (1)	--	20.75	5/15/2022	--	--
	--	--	--	--	250,000 (2)	237,500
Jeffrey M. Slotterback	7,500 (1)	2,500 (3)	24.67	5/15/2022	1,500 (4)	1,545
	--	--	--	--	35,000 (5)	33,250
Sean P. McGrath	--	--	--	--	--	--
Edward E. Cohen	350,000 (1)	--	24.67	5/15/2022	--	--

	--	--	--	--	250,000[2]	237,500
Jonathan Z. Cohen	350,000[1]	--	24.67	5/15/2022	--	--
	--	--	--	--	250,000[2]	237,500
Mark D. Schumacher	--	--	--	--	17,500 [6]	18,025
	--	--	--	--	12,500 [7]	12,875
	--	--	--	--	22,500 [8]	23,175
	--	--	--	--	175,000[9]	166,250
Matthew A. Jones	225,000[1]	--	24.67	5/15/2022	--	--

(1) Represents options to purchase our units.

(2) Represents Atlas Energy Group phantom units, which vest as follows: 6/8/2016—82,500, 6/8/2017—82,500 and 6/8/2018—85,000.

(3) Represents options to purchase our units, which vest as follows: 5/15/2016—2,500.

(4) Represents our phantom units, which vest as follows: 5/15/2016—1,500.

(5) Represents Atlas Energy Group phantom units, which vest as follows: 6/8/2016—11,550, 6/8/2017—11,550 and 6/8/2018—11,900.

(6) Represents our phantom units, which vest as follows: 7/25/2016—17,500.

(7) Represents our phantom units, which vest as follows: 1/24/2016—6,250 and 1/24/2017—6,250.

(8) Represents our phantom units, which vest as follows: 6/26/2016—7,500, 6/26/2017—7,500 and 6/26/2018—7,500.

(9) Represents Atlas Energy Group phantom units, which vest as follows: 6/8/2016—57,750, 6/8/2017—57,750 and 6/8/2018—59,500.

2015 OPTION EXERCISES AND UNITS VESTED TABLE

	Option awards		Unit awards	
Name	Number of units acquired on exercise	Value realized on exercise ($)	Number of units acquired on vesting	Value realized on vesting ($)
Daniel C. Herz	—	—	35,000	343,000
Jeffrey M. Slotterback	—	—	1,500	12,885
Sean P. McGrath	—	—	12,500	107,375
Edward E. Cohen	—	—	75,000	735,000
Jonathan Z. Cohen	—	—	75,000	735,000
Mark D. Schumacher	—	—	31,250	170,475
Matthew A. Jones	—	—	50,000	490,000

2015 NONQUALIFIED DEFERRED COMPENSATION

Name	Executive contributions In the last FY ($)	Registrant contributions in the last FY ($)	Aggregate earnings in the last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate balance at last FYE ($)
Edward E. Cohen	166,250 (1)	166,250 (3)	42,139	928,770 (5)	1,303,408
Jonathan Z. Cohen	146,058 (2)	146,058 (4)	29,907	653,725 (5)	975,748

(1) This amount is included within the Summary Compensation Table for 2015 reflecting $33,251 in the salary column and $132,999 in the non-equity incentive plan compensation column.
(2) This amount is included within the Summary Compensation Table for 2015 reflecting $33,251 in the salary column and $112,807 in the non-equity incentive plan compensation column.
(3) This amount is included within the Summary Compensation Table for 2015 reflecting our allocated portion of a $166,250 matching contribution in the all other compensation column.
(4) This amount is included within the Summary Compensation Table for 2015 reflecting our allocated portion of a $146,058 matching contribution in the all other compensation column.
(5) Messrs. E. and J. Cohen each elected a deferral period of three years after the amount deferred would otherwise have been earned. This amount is included within the Summary Compensation Table for 2015 in the all other compensation column.

Effective July 1, 2011, Atlas Energy established the Excess 401(k) Plan, an unfunded nonqualified deferred compensation plan for certain highly compensated employees. Atlas Energy Group assumed Atlas Energy's obligations under the plan as part of the Separation. The Excess 401(k) Plan provides Messrs. E. and J. Cohen, the plan's current participants, with the opportunity to defer, annually, the receipt of a portion of their compensation, and to permit them to designate investment indices for the purpose of crediting earnings and losses on any amounts deferred under the Excess 401(k) Plan. Messrs. E. and J. Cohen may defer up to 10% of their total annual cash compensation (which means base salary and non-performance-based bonus) and up to 100% of all performance-based bonuses, and Atlas Energy Group is obligated to match such deferrals on a dollar-for-dollar basis (i.e., 100% of the deferral) up to a total of 50% of their base salary for any calendar year. The account is invested in a mutual fund and cash balances are invested daily in a money market account. Atlas Energy established a "rabbi" trust to serve as the funding vehicle for the Excess 401(k) Plan and Atlas Energy Group will, not later than the last day of the first month of each calendar quarter, make contributions to the trust in the amount of the compensation deferred, along with the corresponding match, during the preceding calendar quarter. Notwithstanding the establishment of the rabbi trust, Atlas Energy Group's obligation to pay the amounts due under the Excess 401(k) Plan constitutes a general, unsecured obligation, payable out of its general assets, and Messrs. E. and J. Cohen do not have any rights to any specific asset of the company.

The Excess 401(k) Plan has the following additional provisions:

- At the time the participant makes his deferral election with respect to any year, he must specify the date or dates (but not more than two) on which distributions will start, which date may be upon termination of employment or a date that is at least three years after the year in which the amount deferred would otherwise have been earned. A participant may subsequently defer a specified payment date for a minimum of an additional five years from the previously elected payment date. If the participant fails to make an election, all amounts will be distributable upon the termination of employment.

- Distributions will be made earlier in the event of death, disability or a termination of employment due to a change of control.

- If the participant elects to receive all or a portion of his distribution upon the termination of employment, it will be paid in a lump sum. Otherwise, the participant may elect to receive a lump sum payment or equal installments over not more than 10 years.

- A participant may request a distribution of all or part of his account in the event of an unforeseen financial emergency. An unforeseen financial emergency is a severe financial hardship due to an unforeseeable emergency resulting from a sudden and unexpected illness or accident of the participant, or, a sudden and unexpected illness or accident of a dependent, or loss of the participant's property due to casualty, or other similar and extraordinary unforeseeable circumstances arising as a result of events beyond the control of the participant. An unforeseen financial emergency is not deemed to exist to the extent it is or may be relieved through reimbursement or compensation by insurance or otherwise; by borrowing from commercial sources on reasonable commercial terms to the extent that this borrowing would not itself cause a severe financial hardship; by cessation of deferrals under the plan; or by liquidation of the participant's other assets (including assets of the participant's spouse and minor children that are reasonably available to the participant) to the extent that this liquidation would not itself cause severe financial hardship.

The table above reflects salary and matching contribution costs allocated to us.

DIRECTOR COMPENSATION

The following table sets forth compensation for 2015 for the directors of our general partner's board of directors.

Name	Fees earned or paid in cash($)	Stock awards($)	All other compensation($)[1]	Total($)
Mark C. Biderman	32,548	—	—	32,548
DeAnn Craig	19,111	—	—	19,111
Dennis A. Holtz	26,354	—	—	26,354
Walter C. Jones	26,354	—	—	26,354
Jeffrey C. Key[2]	9,750	—	2,614	12,364
Jeffrey F. Kupfer	23,958	—	—	23,958
Harvey G. Magarick[2]	13,500	—	2,610	16,110
Ellen F. Warren	27,153	—	—	27,153
Bruce Wolf[2]	13,500	—	2,610	16,110

(1) Represents payments on DERs for ATLS phantom units with the exception of Messrs. Key, Magarick and Wolf, which represents payments on DERs for ARP phantom units.
(2) Messrs. Key, Magarick and Wolf served as directors of our general partner until February 23, 2015 when they resigned in connection with the Targa Merger in February 2015.

The following table shows the compensation of the directors of ARP Holdings:

Name	Fees earned or paid in cash($)	Stock awards($)		All other compensation($)[1]	Total($)
Carlton M. Arrendell	32,830	24,997	(2)	1,927	59,754
Tony C. Banks	32,830	24,997	(2)	1,927	59,754
Jeffrey C. Key	32,830	24,997	(2)	1,927	59,754

(1) Represents payments on DERs for ARP phantom units.
(2) This represents 2,910 phantom units granted under the Company’s LTIP, having a grant date fair value of $8.59. The phantom units vest 25% each year as follows: 1/2/16—727, 1/2/17—727, 1/2/18—727 and 1/2/19—729.

Director Compensation

The officers or employees of our general partner who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. In fiscal 2015, the annual retainer for non-employee directors was comprised of $75,000 in cash and an annual grant of phantom units with DERs under the Atlas Energy Group Plan having a fair market value of $125,000. These units will vest ratably over four years beginning on the grant date. The chair of the audit committee received an annual fee of $25,000, the chair of the compensation committee received an annual fee of $10,000, the chairs of the nominating and governance committee and investment committee each received an annual fee of $7,500 and the chair of the environmental, health and safety committee received an annual fee of $5,000. However, since the board of directors of our general partner serves as the board for us as well as our general partner, all of the fees paid in cash to the non-employee directors are allocated 50% to us from our general partner while the annual grant of phantom units under the Atlas Energy Group Plan is not allocated and therefore not reflected as compensation for their service to our company. Therefore, the table above disclosing 2015 compensation to the directors reflects 50% of all of the cash compensation received for their service as a director. See “Item 11: Executive Compensation- 2015 Director Compensation Table” of Atlas Energy Group, LLC’s 10-K for the year ended December 31, 2015, for information regarding the directors’ compensation for their service to Atlas Energy Group, LLC.

For fiscal year 2015, the non-employee directors of ARP Holdings received an annual retainer comprised of $50,000 in cash and an annual grant of phantom units with DERs under our LTIP having a fair market value of $25,000. These units will vest ratably over four years beginning on the grant date.

In January 2016, after approval and recommendation from our general partner's nominating and governance committee, our general partner's board of directors reduced the annual grant of phantom units to non-employee directors of our general partner and ARP Holdings. The non-employee directors of our general partner are now entitled to an amount of phantom units having a fair market value of $50,000, which will vest 50% in 6 months from the date of grant with the remaining 50% to vest six months later. Additionally, our general partner's board of directors limited the annual grant of phantom units to its non-employee directors to 50,000 common units per year. The non-employee directors of ARP Holdings are now entitled to an amount of phantom units having a fair market value of $10,000, which will vest ratably over four years beginning on the grant date and the annual grant of phantom units is limited to 10,000 common units per year.

ITEM 12: SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the number and percentage of our common units owned as of March 2, 2016, by (a) each person who, to our knowledge, is the beneficial owner of more than 5% of the outstanding units, (b) each member of the board of directors of our general partner, (c) each of our executive officers serving during the 2015 fiscal year, and (d) all of our executive officers and members of the board of directors of our general partner as a group. This information is reported in accordance with the beneficial ownership rules of the Securities and Exchange Commission under which a person is deemed to be the beneficial owner of a security if that person has or shares voting power or investment power with respect to such security or has the right to acquire such ownership within 60 days. Units issuable pursuant to options, warrants or phantom units are deemed to be outstanding for purposes of computing the percentage of the person or group holding such options, warrants or phantom units but are not deemed to be outstanding for purposes of computing the percentage of any other person. Unless otherwise indicated in footnotes to the table, each person listed has sole voting and dispositive power with respect to the securities owned by such person.

Beneficial owner	Common unit amount and nature of beneficial ownership		Percent of class
Directors [1]			
Mark C. Biderman	1,746		*
Edward E. Cohen	924,743	(2)	*
Jonathan Z. Cohen	896,586	(3)	*
Jeffrey F. Kupfer	1,183		*
Dennis A. Holtz	618		*
Walter C. Jones	-		*
Ellen F. Warren	186		*
DeAnn Craig	5,114	(4)	*
Non-director Executive Officers[1]			
Daniel C. Herz	155,130	(5)	*
Freddie M. Kotek	98,660	(6)	*
Jeffrey M. Slotterback	11,579	(7)	*
Mark D. Schumacher	107,202		

Dave Leopold	22,047	(8)	*	
Lisa Washington	14,999	(9)	*	
Matthew J. Finkbeiner	-		*	
Sean P. McGrath	66,675	(10)(11)	*	
Matthew A. Jones	338,273	(12)(13)	*	
All executive officers, directors and nominees as a group (17 persons)	2,327,528	(14)	2.25	%
Other owners of more than 5% of outstanding units				
Atlas Energy Group, LLC[1]	25,274,968	(15)	24.7	%
R/C Energy IV TGP [16]	7,593,800		7.4	%

* Less than 1%

(1) The business address for each director and executive officer as well as for Atlas Energy Group, LLC is Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, PA 15275-1011.

178

(2) Includes (i) 2,680 units held in an individual retirement account of Mr. E. Cohen's spouse; (ii) 40,896 units held by a partnership of which Mr. E. Cohen and his spouse are the sole limited partners and sole stockholders, officers and directors of the general partner; (iii) 310,344 units held by a charitable foundation of which Mr. E. Cohen, his spouse and their children serve as co-trustees; (iv) 6,869 units held by a trust (of which Mr. E. Cohen is the settlor) for the benefit of his spouse; (v) 7,510 units owned by a trust for the benefit of Mr. E. Cohen's children; (vi) 766 units owned by a trust (of which Mr. E. Cohen is the settlor) for the benefit of his spouse and/or children; and (vii) 350,000 common unit purchase options. Mr. E. Cohen disclaims beneficial ownership of the units described above except for those set forth in (ii) and (vii) above. 317,213 of these units are also included in the common units referred to in footnote 3 below.
(3) Includes (i) 229,373 units jointly owned by Mr. J. Cohen and his spouse; (ii) 310,344 units held by a charitable foundation of which Mr. J. Cohen, his parents and his sibling serve as co-trustees; (iii) 6,869 units owned by a trust of which Mr. J. Cohen and his sibling are each trustees and beneficiaries; and (iv) 350,000 common unit purchase options. Mr. J. Cohen disclaims beneficial ownership to the units described above in (ii).
(4) Includes 1,373 phantom units that will vest and convert into common units within 60 days.
(5) Includes 100,000 common unit purchase options.
(6) Includes (i) 25,278 units held by spouse; (ii) 5,828 units held by his children's trust; (iii) 195 units held by his children; (iv) 659 units held by his mother-in-law; and (v) 52,500 common unit purchase options.
(7) Includes 7,500 common unit purchase options.
(8) Includes 6,250 phantom units that will vest and convert into common units within 60 days.
(9) Includes 9,375 common unit purchase options.
(10) Includes 37,500 common unit purchase options.
(11) We announced in August 2015 that Mr. McGrath resigned from his position as Chief Financial Officer; his ownership amount represents the common units that he held upon his resignation.
(12) Includes 225,000 common unit purchase options.
(13) We announced in April 2015 that Mr. Jones retired from his position as Senior Vice President of Atlas Energy Group and President, ARP; his ownership amount represents the common units that he held upon his retirement.
(14) This number has been adjusted to exclude 6,869 common units and 310,344 common units which were included in both Mr. E. Cohen's beneficial ownership amount and Mr. J. Cohen's beneficial ownership amount.
(15) Includes 3,749,986 Class C Convertible Preferred Units and 562,497 warrants to purchase common units.
(16) This information is based on a Schedule 13G filed by R/C Energy IV TGP Holdings, L.P., Riverstone/Carlyle Energy Partners IV, L.P., and R/C Energy GP IV, LLC (collectively, "R/C Energy IV") with the SEC on August 6, 2012. The address for R/C Energy is 712 Fifth Avenue, 51st Floor, New York, NY 10019.

Equity Compensation Plan Information

The following table contains information about our Plan as of December 31, 2015:

Plan category	Number of securities to be issued upon exercise of equity instruments	Weighted-average exercise price of outstanding equity instruments	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in

			column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders – phantom units	302,105	n/a	
Equity compensation plans approved by security holders – unit options	1,352,525	$ 24.66	
Equity compensation plans approved by security holders – Total	1,656,630		187,633

The following table contains information about Atlas Energy Group's Long-Term Incentive Plan as of December 31, 2015:

Plan category	Number of securities to be issued upon exercise of equity instruments (a)	Weighted-average exercise price of outstanding equity instruments (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders – phantom units	2,564,910	N/A	
Equity compensation plans approved by security holders – unit options	N/A	$ N/A	
Equity compensation plans approved by security holders – Total	2,564,910		2,685,090

180

ITEM 13: CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The board of directors of our general partner has determined that Dr. Craig, Ms. Warren and Messrs. Biderman, Holtz, Jones and Kupfer each satisfy the requirement for independence set out in the rules of the New York Stock Exchange and those set forth in Rule 10A-3(b)(1) of the Securities Exchange Act of 1934, and each of them meet the definition of an independent member set forth in our Partnership Governance Guidelines. Additionally, the board of directors of our general partner determined that Messrs. Arrendell, Banks and Key, the three disinterested members of the board of managers of ARP Holdings, are each independent with respect us, as defined by the rules of the New York Stock Exchange and the independence standards adopted by our general partner's board of directors. In making these determinations, the board of directors reviewed information from each of these board members concerning all their respective relationships with us and analyzed the materiality of those relationships.

We have a written policy governing related party transactions. For purposes of this policy, a related party includes: (i) any executive officer, director or director nominee; (ii) any person known to be a beneficial owner of 5% or more of our common units; (iii) an immediate family member of any person included in clauses (i) and (ii) (which, by definition, includes, a person's spouse, parents, and parents in law, step parents, children, children in law and step children, siblings and brothers and sisters in law and anyone residing in that person's home); and (iv) any firm, corporation or other entity in which any person included in clauses (i) through (iii) above is employed as an executive officer, is a director, partner, principal or occupies a similar position or in which that person owns a 5% or more beneficial interest. Any transaction between us and a related party that is anticipated to exceed $120,000 in any calendar year must be approved, in advance, by the disinterested members of the board of managers ("ARP Holdings Board") of Atlas Resource Partners Holdings, LLC ("ARP Holdings"), our wholly-owned subsidiary,. ARP Holdings, following the approval of a related party transaction, is required to notify our general partner's board of directors of such approval and provide the board of directors with a summary of each related party transaction at the next meeting of the board of directors. If consideration by the disinterested members of the ARP Holdings Board in advance is not feasible, then the related party transaction shall be considered, and, if the disinterested members determined it to be appropriate, the related party transaction must be ratified at the next meeting of the ARP Holdings Board. In determining whether to recommend the approval or ratification of a related party transaction, the disinterested members of the ARP Holdings Board will take into account, among other factors they deem appropriate, whether the related party transaction is on terms no less favorable than terms generally available to an unaffiliated third party under the same or similar circumstances, and the extent of the related party's interest in the transaction. The disinterested members of the ARP Holdings Board, following the approval of a related party transaction, will notify our general partner's board of directors of such approval and provide the board of directors with their recommendation. The general partner's board of directors then meet to consider the related party transaction with the non-independent members of the general partner's board of directors recusing themselves from voting on the transaction.

Disinterested members of the ARP Holdings Board with respect to a related party transaction means all members of the ARP Holdings Board who (i) are not officers or employees of Atlas Energy Group, (ii) are not officers, directors or employees of any affiliate of Atlas Energy Group (other than because any such person serves as a member of the ARP Holdings Board), (iii) are not holders of any ownership interest in us or Atlas Energy Group, other than a de minimis interest or common units representing limited partnership interests in us or other awards granted to such persons under our equity compensation plans and (iv) do not have a direct or indirect interest in such related party transaction.

The following related party transactions are pre-approved under the policy: (i) employment of an executive officer to perform services on our behalf (or on behalf of one of our subsidiaries) if (a) the compensation is required to be reported in our annual report on Form 10-K or (b) the executive officer is not an immediate family member and such compensation was approved, or recommended to our general partner's board of directors for approval, by its compensation committee; (ii) compensation paid to directors for serving on the board of directors of our general partner or any committee thereof or reimbursement of expenses in connection with such services, if the compensation is required to be reported in our annual report on Form 10-K; (iii) transactions where the related party's interest arises solely as a holder of our common units and all holders of our common units received the same benefit on a pro rata basis (e.g., dividends), or transactions available to all employees generally; (iv) a transaction at another company where the related party is only an employee (and not an executive officer), director or beneficial owner of less than 10% of such company's shares and the aggregate amount involved does not exceed the greater of $1,000,000 or 2% of that company's total annual revenues; and (v) any charitable contribution, grant or endowment by us or our general partner to a charitable organization, foundation or university at which the related party's only relationship is an employee (other than an executive officer) or director or similar capacity, if the aggregate amount involved does not exceed the lesser of $200,000 or 2% of the charitable organization's total annual receipts, expenditures or assets.

Our Relationship with Atlas Energy Group and Atlas Energy

Atlas Energy Group owns approximately 20.96 million of our outstanding common units and 3.75 million Class C convertible preferred units, representing approximately 23.3% limited partner ownership interest in us. In addition, Atlas Energy Group owns 2,161,445 Class A units, representing a 2% general partner interest, and all of our incentive distribution rights. As the owner of our incentive distribution rights, Atlas Energy Group will be entitled to receive increasing percentages, up to a maximum of 50%, of any cash distributed by us as we reach certain target distribution levels in excess of $0.46 per common unit in any quarter. Until February 27, 2015, Atlas Energy owned the common and preferred, and our general partner was its wholly owned subsidiary. As part of the separation from Atlas Energy on February 27, 2015, Atlas Energy contributed the common and preferred interests to Atlas Energy Group.

We are required by our partnership agreement to distribute all of our “available cash,” as defined in our partnership agreement, at the end of each quarter. “Available cash” is generally defined to include all our cash on hand at the end of any quarter, less reserves established by our general partner, in its sole discretion to provide for the proper conduct of our business or to provide for future distributions. Our general partner will be reimbursed for direct and indirect expenses incurred on our behalf.

We do not currently directly employ any persons to manage or operate our business. These functions are provided by employees of Atlas Energy Group and/or its affiliates. Our general partner does not receive a management fee in connection with its management of us apart from its class A units in us and its right to receive incentive distributions. We reimburse our general partner and its affiliates for expenses they incur in managing our operations, and for an allocation of the compensation paid to our general partner’s executive officers based upon an estimate of the time spent by such persons on activities for us. Other indirect costs, such as rent for offices, are allocated to us by our general partner based on the number of its employees who devote substantially all of their time to activities on our behalf. We reimburse our general partner at cost for direct costs incurred by them on our behalf. Our partnership agreement provides that our general partner will determine the costs and expenses that are allocable to us at its sole discretion, and does not set any aggregate limit on the amount of such reimbursements. We reimbursed Atlas Energy Group, our general partner, and its affiliates $5.2 million for the year ended December 31, 2015 for compensation and benefits related to their employees.

In June 2015, we completed the acquisition of Atlas Energy Group’s coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments. We funded the purchase price through the issuance of 6,500,000 common limited partner units.

In July 2013, in connection with the EP Energy Acquisition, we issued $86.6 million of our newly created Class C convertible preferred units to Atlas Energy, at a negotiated price per unit of $23.10, which is the face value of the units. The Class C preferred units pay cash distributions in an amount equal to the greater of (i) $0.51 per unit and (ii) the distributions payable on each common unit at each declared quarterly distribution date. The Class C preferred units have no voting rights, except as set forth in the certificate of designation for the Class C preferred units, which provides, among other things, that the affirmative vote of 75% of the Class C Preferred Units is required to repeal such certificate of designation. Holders of the Class C preferred units have the right to convert the Class C preferred units on a one-for-one basis, in whole or in part, into common units at any time before July 31, 2016. Unless previously converted, all Class C preferred units will convert into common units on July 31, 2016. Upon issuance of the Class C preferred units, Atlas Energy, as purchaser of the Class C preferred units, received 562,497 warrants to purchase our common units at an exercise price equal to the face value of the Class C preferred units. The warrants were exercisable beginning October 29, 2013 into an equal number of our common units at an exercise price of $23.10 per unit, subject to adjustments provided therein. The warrants will expire on July 31, 2016. Atlas Energy contributed the Class C preferred units and the warrants to Atlas Energy Group in the separation on February 27, 2015. We paid $7.8 million in distributions on the Class C convertible preferred units to Atlas Energy Group for the year ended December 31, 2015.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership securities proposed to be sold by our general partner or any of its affiliates if an exemption from the registration requirements is not otherwise available. There is no limit on the number of times that we may be required to file registration statements pursuant to this obligation. We have also agreed to include any securities held by our general partner or any of its affiliates in any registration statement that we file to offer securities for cash, other than an offering relating solely to an employee benefit plan. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions. In connection with any registration of this kind, we will indemnify the unitholders participating in the registration and their officers, directors and controlling persons from and against specified liabilities, including under the Securities Act or any applicable state securities laws.

Upon issuance of the Class C preferred units and warrants on July 31, 2013, we entered into a registration rights agreement pursuant to which we agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and upon exercise of the warrants. We agreed to use commercially reasonable efforts to file such registration statement within 90 days of the conversion of the Class C preferred units into common units or the exercise of the warrants. We filed a registration statement to register for resale the common units underlying the Class C preferred units on March 17, 2015 and the registration statement was declared effective on March 27, 2015.

Relationship with Atlas Growth Partners

Eagle Ford Acquisition

On November 5, 2014, we, together with AGP, completed an acquisition of oil and NGL interests in the Eagle Ford Shale in Atascosa County, Texas from Cinco Resources, Inc. and Cima Resources, LLC, a wholly owned subsidiary of Cinco (together "Cinco"), for an aggregate purchase price of $342.0 million, net of purchase price adjustments (the "Eagle Ford Acquisition"). We paid approximately $183.1 million in cash and AGP paid approximately $19.9 million at closing, and approximately $139.0 million was to be paid in four quarterly installments beginning December 31, 2014. On December 31, 2014, AGP made its first installment payment of $35.0 million. Prior to the March 31, 2015 installment, we, AGP, and Cinco amended the purchase and sale agreement to alter the timing and amount of the quarterly payments beginning with the March 31, 2015 payment and ending December 31, 2015, with no change to the overall purchase price. On March 31, 2015, AGP paid $28.3 million in cash and we issued $20.0 million of our Class D Preferred Units to satisfy the second installment related to the Eagle Ford Acquisition. On June 30, 2015, AGP paid $16.0 million and we paid $0.6 million, in cash, to satisfy the third installment related to the Eagle Ford Acquisition.

On September 21, 2015, we and AGP agreed that we would fund AGP's remaining two deferred purchase price installments of $16.2 million and $20.1 million to be paid on September 30, 2015 and December 31, 2015, respectively. In conjunction therewith, AGP assigned to us a portion of its non-operating Eagle Ford assets that had an allocated value (as such value was agreed upon by the sellers and the buyers in connection with the Eagle Ford Acquisition) equal to both installments to be paid by us. As a result, our share of the aggregate purchase price was $242.8 million, net of purchase price adjustments. The Eagle Ford Acquisition had an effective date of July 1, 2014.

Sale of Oil and Natural Gas Properties

On July 8, 2015, AGP sold to us a portion of the wells it acquired in the Eagle Ford acquisition for a purchase price of $1.4 million, which represented its cost for the properties.

All of these transactions were approved by our and AGP's respective independent conflicts committees.

Relationship with Resource America

Edward E. Cohen, our Chief Executive Officer, serves as Chairman of Resource America, Inc. ("Resource America") and is a greater than 10% shareholder, and Jonathan Z. Cohen, our Executive Chairman, serves as Chief Executive Officer and President of Resource America and is a greater than 10% shareholder. Resource America subleases office space from us and paid us $0.1 million for the fiscal year ended December 31, 2015. We reimbursed Resource America for other shared services and paid Resource America $0.2 million for the fiscal year ended December 31, 2015.

ITEM 14: PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2015 and 2014, the accounting fees and services (in thousands) charged by Grant Thornton, LLP, our independent auditors, were as follows:

	Years Ended December 31,	
	2015	2014
Audit fees(1)	$1,199	$1,302
Audit-related fees(2)	67	85
Tax fees(3)	98	119
All other fees	—	—
Total accounting fees and services	$1,364	$1,506

(1) Represents the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP principally for the audits of our annual financial statements and the reviews of our quarterly financial statements included in Form 10-Qs and also for services related to registration statements, Form 8-Ks and comfort letters.

(2) Represents the aggregate fees recognized during the years ended December 31, 2015 and 2014 for professional services rendered by Grant Thornton LLP substantially related to certain necessary audit related services in connection with the registration and/or private placement of our Drilling Partnerships.

(3) Represent the fees for tax services rendered related to tax compliance.

Audit Committee Pre-Approval Policies and Procedures

The audit committee of our general partner, on at least an annual basis, will review audit and non-audit services performed by Grant Thornton LLP as well as the fees charged by Grant Thornton LLP for such services. Our policy is that all audit and non-audit services must be pre-approved by the audit committee. All of such services and fees were pre-approved during 2015 and 2014.

PART IV

ITEM 15: EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

(1) Financial Statements

The financial statements required by this Item 15(a)(1) are set forth in “Item 8: Financial Statements and Supplementary Data”.

(2) Financial Statement Schedules

None

(3) Exhibits:

Exhibit No.	Description
2.1(a)	Purchase and Sale Agreement, dated September 24, 2014, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request [30]
2.1(b)	First Amendment to Purchase and Sale Agreement dated October 27, 2014, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. [34]
2.1(c)	Second Amendment to Purchase and Sale Agreement dated March 31, 2015, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. [37]
2.2(a)	Shared Acquisition and Operating Agreement, dated September 24, 2014, by and among ARP Eagle Ford, LLC and Atlas Growth Eagle Ford, LLC. The schedules to the Shared Acquisition and Operating Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request [30]
2.2(b)	Amended and Restated Shared Acquisition and Operating Agreement, effective as of September 24, 2014, by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC. The schedules to the Amended and Restated Shared Acquisition and Operating Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.[14]
2.2(c)	Addendum #2 to the Amended and Restated Shared Acquisition and Operating Agreement by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC, effective as of July 1, 2015. The schedules to Addendum #2 to the Amended and Restated Shared Acquisition and Operating Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request. [14]

2.2(d)	Addendum #3 to the Amended and Restated Shared Acquisition and Operating Agreement by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC, effective as of September 30, 2015. The schedules to Addendum #3 to the Amended and Restated Shared Acquisition and Operating Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request. (14)
2.3	Purchase and Sale Agreement, dated May 18, 2015, by and between New Atlas Holdings, LLC and ARP Production Company, LLC. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request (40)
3.1	Certificate of Limited Partnership of Atlas Resource Partners, L.P.(2)
3.2(a)	Amended and Restated Limited Partnership Agreement of Atlas Resource Partners, L.P.(4)

Exhibit No.	Description
3.2(b)	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of July 25, 2012[12]
3.2(c)	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of July 31, 2013[6]
3.2(d)	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of October 2, 2014[31]
3.2(e)	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of November 3, 2014[33]
3.2(f)	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of February 27, 2015 [39]
3.2(g)	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of April 14, 2015 [38]
3.3(a)	Certificate of Formation of Atlas Resource Partners GP, LLC[2]
3.3(b)	Certificate of Amendment to Certificate of Formation of Atlas Resource Partners GP, LLC dated as of November 3, 2014[33]
3.4(a)	Second Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC[24]
3.4(b)	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC dated as of November 3, 2014[33]
3.4(c)	Third Amended and Restated Limited Liability Company Agreement of Atlas Energy Group, LLC, dated as of February 27, 2015[26]
3.4(d)	Amendment No. 1 to the Third Amended and Restated Limited Liability Company Agreement of Atlas Energy Group, LLC, dated as of February 27, 2015[26]
4.1(a)	Indenture dated as of January 23, 2013 among Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the subsidiaries named therein and U.S. Bank National Association[20]
4.1(b)	Supplemental Indenture dated as of June 2, 2014 among Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the subsidiaries named therein and U.S. Bank National Association[29]
4.1(c)	Second Supplemental Indenture dated as of July 23, 2015, among Atlas Resource Partners Holdings, LLC (f/k/a Atlas Energy Holdings Operating Company, LLC), Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the subsidiaries named therein and U.S. Bank National Association[42]

4.1(d)	Third Supplemental Indenture dated as of December 29, 2015, among Atlas Resource Partners Holdings, LLC (f/k/a Atlas Energy Holdings Operating Company, LLC), Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the subsidiaries named therein and U.S. Bank National Association[46]
4.2(a)	Indenture dated as of July 30, 2013, by and between Atlas Resource Escrow Corporation and Wells Fargo Bank, National Association[22]
4.2(b)	Supplemental Indenture dated as of July 31, 2013, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Bank, National Association[22]
4.2(c)	Second Supplemental Indenture dated as of October 14, 2014, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Bank, National Association[32]

Exhibit No.	Description
4.2(d)	Third Supplemental Indenture dated as of July 23, 2015, by and among Atlas Resource Partners, L.P., Atlas Resource Partners Holdings, LLC (f/k/a Atlas Energy Holdings Operating Company, LLC), Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Bank, National Association[(42)]
4.2(e)	Fourth Supplemental Indenture dated as of December 17, 2015, by and among Atlas Resource Partners, L.P., Atlas Resource Partners Holdings, LLC (f/k/a Atlas Energy Holdings Operating Company, LLC), Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Bank, National Association[(47)]
4.3	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class B Preferred Units, dated as of July 25, 2013[(12)]
4.4	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class C Convertible Preferred Units, dated as of July 31, 2013[(6)]
4.5	Warrant to Purchase Common Units[(6)]
4.6	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of 8.625% Class D Cumulative Redeemable Perpetual Preferred Units, dated as of October 2, 2014[(31)]
4.7	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class E Cumulative Redeemable Perpetual Preferred Units, dated as of April 14, 2015[(38)]
10.1	Secured Hedge Facility Agreement, among Atlas Resources, LLC, the participating partnerships from time to time party thereto, the hedge providers from time to time party thereto and Wells Fargo Bank, N.A., as collateral agent for the hedge providers[(3)]
10.2(a)	Second Amended and Restated Credit Agreement dated July 31, 2013 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(6)]
10.2(b)	First Amendment to Second Amended and Restated Credit Agreement dated December 6, 2013 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(28)]
10.2(c)	Third Amendment to Second Amended and Restated Credit Agreement dated June 30, 2014 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(29)]
10.2(d)	Fourth Amendment to Second Amended and Restated Credit Agreement dated September 24, 2014 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(30)]

10.2(e)	Fifth Amendment to Second Amended and Restated Credit Agreement dated November 24, 2014 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(10)]
10.2(f)	Sixth Amendment to Second Amended and Restated Credit Agreement, dated February 23, 2015, by and among Atlas Resource Partners, L.P., Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto[(36)]
10.2(g)	Seventh Amendment to Second Amended and Restated Credit Agreement dated as of July 24, 2015 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders
10.2(h)	Eighth Amendment to Second Amended and Restated Credit Agreement dated as of November 23, 2015 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(25)]
10.3	Second Lien Credit Agreement, dated February 23, 2015, by and among Atlas Resource Partners, L.P., Wilmington Trust, National Association, as administrative agent, and the lenders party thereto[(36)]
10.4	2012 Long-Term Incentive Plan of Atlas Resource Partners, L.P. [(4)]
10.5	Form of Phantom Unit Grant Agreement under 2012 Long-Term Incentive Plan[(8)]
10.6	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan[(8)]
10.7	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan[(8)]

Exhibit No.	Description
10.8	Registration Rights Agreement, dated March 31, 2015, by and between Cinco Resources, Inc. and Atlas Resource Partners, L.P.[37]
10.9	Amended and Restated Registration Rights Agreement, dated as of July 31, 2013, between Atlas Resource Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Amended and Restated Credit Agreement dated July 31, 2013 by and among Atlas Energy, L.P. and the lenders named therein[39]
10.10	Registration Rights Agreement dated as of June 2, 2014, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein Wells Fargo Securities, LLC and Deutsche Bank Securities, Inc [29]
10.11	Registration Rights Agreement dated as of July 31, 2013, by and among Atlas Energy, L.P. and Atlas Resource Partners, L.P. [6]
10.12	Registration Rights Agreement dated as of October 14, 2014, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Securities, LLC, for itself and on behalf of the Initial Purchasers [32]
10.13	Registration Rights Agreement dated as of February 27, 2015, by and between Atlas Resource Partners, L.P. and Deutsche Bank AG New York Branch LLC [48]
10.14	Distribution Agreement dated as of August 29, 2014, between Atlas Resource Partners, L.P. and Deutsche Bank Securities Inc., as representative of the several lenders[35]
10.15	Distribution Agreement dated as of November 13, 2015, between Atlas Resource Partners, L.P., MLV & Co. LLC and FBR Capital Markets & Co. [43]
10.16	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Edward E. Cohen, dated September 4, 2015[44]
10.17	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Jonathan Z. Cohen, dated September 4, 2015[44]
10.18	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Daniel C. Herz, dated September 4, 2015[44]
10.19	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Mark Schumacher, dated September 4, 2015[44]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Atlas Resource Partners, L.P.
23.1	Consent of Grant Thornton LLP

23.2	Consent of Wright and Company, Inc.
23.3	Consent of Cawley, Gillespie, and Associates, Inc.
31.1	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2	Rule 13(a)-14(a)/15(d)-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification
99.1	Atlas Resource Partners, L.P. - Partnership Agreement and Distribution Policy(45)
99.2	Summary Reserve Report of Wright & Company, Inc.
99.3	Rangely Summary Reserve Report of Cawley, Gillespie, and Associates, Inc.
101.INS	XBRL Instance Document(27)

Exhibit No.	Description
101.SCH	XBRL Schema Document[(27)]
101.CAL	XBRL Calculation Linkbase Document[(27)]
101.LAB	XBRL Label Linkbase Document[(27)]
101.PRE	XBRL Presentation Linkbase Document[(27)]
101.DEF	XBRL Definition Linkbase Document[(27)]

(1) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 31, 2013.
(2) Previously filed as an exhibit to our Registration Statement on Form 10, as amended (File No. 1-35317).
(3) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 7, 2012.
(4) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 14, 2012.
(5) Previously filed as an exhibit to Atlas Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.
(6) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 6, 2013
(7) Previously filed as an exhibit to Atlas Energy's Annual Report on Form 10-K for the year ended December 31, 2011.
(8) Previously filed as an exhibit to our Annual Report on Form 10-K filed for the year ended December 31, 2011.
(9) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 21, 2012.
(10) Previously filed as an exhibit to our Current Report on Form 8-K filed on November 25, 2014.
(11) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 10, 2013.
(12) Previously filed as an exhibit to our Current Report on Form 8-K filed on July 26, 2012.
(13) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.
(14) Previously filed as an exhibit to our quarterly report on Form 10-Q for the quarter ended September 30, 2015.
(15) Previously filed as an exhibit to our Current Report on Form 8-K filed on December 26, 2012.
(16) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 11, 2013.
(17) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 17, 2013.
(18) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.
(19) Previously filed as an exhibit to our Current Report on Form 8-K filed on November 27, 2012.
(20) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 25, 2013.
(21) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 14, 2013.
(22) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 2, 2013.
(23) Previously filed as an exhibit to Atlas Energy's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013.
(24) Previously filed as an exhibit to our quarterly report on Form 10-Q for the quarter ended September 30, 2013.
(25) Previously filed as an exhibit to our Current Report on Form 8-K filed on November 25, 2015.
(26) Previously filed as an exhibit to Atlas Energy Group, LLC's current report on Form 8-K filed on March 2, 2015.
(27) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed".
(28) Previously filed as an exhibit to our Annual Report on Form 10-K filed for the year ended December 31, 2013.
(29) Previously filed as an exhibit to our current report on Form 8-K filed on June 3, 2014.
(30) Previously filed as an exhibit to our current report on Form 8-K filed on September 30, 2014.
(31) Previously filed as an exhibit to our current report on Form 8-K filed on October 2, 2014.

(32) Previously filed as an exhibit to our current report on Form 8-K filed on October 15, 2014.
(33) Previously filed as an exhibit to our current report on Form 8-K filed on November 5, 2014.
(34) Previously filed as an exhibit to our current report on Form 8-K filed on November 6, 2014.
(35) Previously filed as an exhibit to our current report on Form 8-K filed on August 29, 2014.
(36) Previously filed as an exhibit to our current report on Form 8-K filed on February 23, 2015.
(37) Previously filed as an exhibit to our current report on Form 8-K filed on April 6, 2015.
(38) Previously filed as an exhibit to our registration statement on Form 8-A filed on April 14, 2015.
(39) Previously filed as an exhibit to our Annual Report on Form 10-K for the year ended December 31, 2014.
(40) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 22, 2015.
(41) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 2, 2015.
(42) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2015.
(43) Previously filed as an exhibit to our Current Report on Form 8-K filed on November 13, 2015.
(44) Previously filed as an exhibit to our Current Report on Form 8-K filed on September 4, 2015.
(45) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015.
(46) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 5, 2016.
(47) Previously filed as an exhibit to our Current Report on Form 8-K filed on December 23, 2015.

(48) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 2, 2015.

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.

	ATLAS RESOURCE PARTNERS, L.P. By: Atlas Energy Group, LLC, its General Partner
Date: March 4, 2016	By: /s/ DANIEL C. HERZ Daniel C. Herz Chief Executive Officer of ARP

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated as of March 4, 2016.

/s/ EDWARD E. COHEN Edward E. Cohen	Executive Chairman of ARP
/s/ JONATHAN Z. COHEN Jonathan Z. Cohen	Executive Vice Chairman of ARP
/s/ DANIEL C. HERZ Daniel C. Herz	Chief Executive Officer of ARP (Principal Executive Officer)
/s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback	Chief Financial Officer of ARP (Principal Financial Officer)
/s/ MATTHEW J. FINKBEINER Matthew J. Finkbeiner	Chief Accounting Officer of ARP (Principal Accounting Officer)
/s/ MARK C. BIDERMAN Mark C. Biderman	Director of the General Partner
/s/ DEANN CRAIG DeAnn Craig	Director of the General Partner
/s/ DENNIS A. HOLTZ Dennis A. Holtz	Director of the General Partner
/s/ WALTER C. JONES Walter C. Jones	Director of the General Partner

/s/ JEFFREY F. KUPFER Jeffrey F. Kupfer	Director of the General Partner
/s/ ELLEN F. WARREN Ellen F. Warren	Director of the General Partner