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, 2013

OR

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

For the transition period from   to

Commission file number: 001-35317

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 Pittsburgh, PA (Address of principal executive offices)	15275 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

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

None

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

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

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 ¨

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. ¨

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No 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, 2013, was approximately $829.1 million.

The number of outstanding common limited partner units of the registrant on February 25, 2014 was 59,464,433.

DOCUMENTS INCORPORATED BY REFERENCE: None

ATLAS RESOURCE PARTNERS, L.P.

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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. has 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, unless the context otherwise requires.

Bbl. One stock tank barrel or 42 United States gallons liquid volume.

Bcf. One billion cubic feet.

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. 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. Acres spaced or assigned to productive wells.

Development well. A well drilled within a 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. An exploratory, development or extension well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil and 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. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well as those items are defined in this section.

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.

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 oil or other liquid hydrocarbons.

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Mcf. One thousand cubic feet.

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

Mcfd. One thousand cubic feet per day.

Mcfed. One Mcfe per day.

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using a ratio of six Mcf of gas to one Bbl of 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.

NGL. Natural gas liquids, which are the hydrocarbon liquids contained within gas.

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.

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 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.

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

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

Reserves. Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.

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

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. Lease acreage on which wells have not been drilled and where it is either probable or possible that the acreage contains reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of 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 market price of our common units;

· future financial and operating results;

· resource potential;

· realized natural gas and oil prices;

· economic conditions and instability in the financial markets;

· 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 dividends or distributions, or failure to declare a dividend or distribution, on outstanding common units or other equity securities;

- any issuance of additional common units or other equity securities, and any resulting dilution or decline in the market price of any such securities;

- restrictive covenants in indebtedness that may adversely affect operational flexibility;

- potential changes in tax laws which may impair the ability to obtain capital funds through investment partnerships;

- the ability to raise funds through investment or through access to the capital markets;

- 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;

- 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 related 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;
- 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;
- exposure to new and existing litigation;

· the potential failure to retain certain key employees and skilled workers; and

· development of alternative energy resources.

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, 2013, our estimated proved reserves were 1,169 Bcfe, including the reserves net to our equity interest in our Drilling Partnerships. Of our estimated proved reserves, approximately 68% were proved developed and approximately 83% were natural gas. For the year ended December 31, 2013, our average daily net production was approximately 187.7 MMcfe. Through December 31, 2013, we own production positions in the following areas:

- the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas. We have ownership interests in approximately 620 wells in the Barnett Shale and Marble Falls play and 484 Bcfe of total proved reserves with average daily production of 86.4 MMcfe for the year ended December 31, 2013;

- the 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. We have ownership interests in approximately 2,950 wells in the Raton, Black Warrior, and County Line areas and 433 Bcfe of total proved reserves with average daily production of 47.8 MMcfe for the year ended December 31, 2013;

- the Appalachia Basin, including the Marcellus Shale and the Utica Shale. We have ownership interests in approximately 8,170 wells primarily in the Appalachian Basin, including approximately 270 wells in the Marcellus Shale and 160 Bcfe of total proved reserves with average daily production of 38.8 MMcfe for the year ended December 31, 2013;

- the Mississippi Lime and Hunton plays in northwestern Oklahoma. We own 76 Bcfe of total proved reserves with average daily production of 7.8 MMcfe for the year ended December 31, 2013; 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 17 Bcfe of total proved reserves with average daily production of 6.8 MMcfe for the year ended December 31, 2013.

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. Overall, we have acquired significant net proved reserves and production through the following transactions:

- Carrizo Barnett Shale Acquisition – On April 30, 2012, we acquired 277 Bcfe of proved reserves, including undeveloped drilling locations, in the core of the Barnett Shale from Carrizo Oil & Gas, Inc. (NASD: CRZO; "Carrizo") for approximately $187.0 million (the "Carrizo Acquisition"). The assets included 198 gross producing wells generating approximately 31 MMcfed of production at the date of acquisition on over 12,000 net acres, all of which are held by production.

- Titan Barnett Shale Acquisition – On July 26, 2012, we acquired Titan Operating, L.L.C. ("Titan"), which owned approximately 250 Bcfe of proved reserves and associated assets in the Barnett Shale on approximately 16,000 net acres, which are 90% held by production, for approximately $208.6 million (the "Titan Acquisition"). Titan's assets are located in close proximity to the assets acquired from Carrizo in the Barnett Shale. Net production from these assets at the date of acquisition was approximately 24 MMcfed, including approximately 370 Bpd of natural gas liquids. We believe there are over 300 potential undeveloped drilling locations on the Titan acreage.

- Equal Mississippi Lime Acquisition – On April 4, 2012, we entered into an agreement with Equal Energy, Ltd. (NYSE: EQU; TSX: EQU; "Equal") to acquire a 50% interest in Equal's approximately 14,500 net undeveloped acres in the core of the oil and liquids rich Mississippi Lime play in northwestern Oklahoma for approximately $18.0 million. On September 24, 2012, we acquired Equal's remaining 50% interest in approximately 8,500 net undeveloped acres included in the joint venture, approximately 8 MMcfed of net production in the region at the date of acquisition and substantial salt water disposal infrastructure for $41.3 million (the "Equal Acquisition"). The transaction increased our position in the Mississippi Lime play to 19,800 net acres in Alfalfa, Grant and Garfield counties in Oklahoma.

- DTE Fort Worth Basin Acquisition – On December 20, 2012, we acquired 210 Bcfe of proved reserves in the Fort Worth basin from DTE Energy Company (NYSE: DTE; "DTE") for $257.4 million (the "DTE Acquisition"). The assets included 261 gross producing wells generating approximately 23 MMcfed of production at the date of acquisition on over 88,000 net acres, approximately 40% of which are held by production and approximately 33% are in continuous development. The acreage position includes approximately 75,000 net acres prospective for the oil and NGL-rich Marble Falls play, in which there are over 700 identified vertical drilling locations. We spud approximately 70 vertical wells during 2013 and plan to continue our development during 2014. We believe that there are further potential development opportunities through vertical down-spacing and horizontal drilling in the Marble Falls formation. The assets acquired from DTE are in close proximity to our other assets in the Barnett Shale.

- EP Energy Raton Basin, Black Warrior Basin and County Line 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"). Pursuant to the purchase and sale agreement, we acquired interests in 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. We believe there are approximately 1,600 potential undeveloped drilling locations on the acreage acquired. 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.

Our general partner, Atlas Energy, L.P. ("ATLS"), a publicly traded master-limited partnership (NYSE: ATLS), manages our operations and activities through its ownership of our general partner interest. At December 31, 2013, ATLS 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 36.9% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

We were formed in October 2011 to own and operate substantially all of ATLS' exploration and production assets, which were transferred to us on March 5, 2012.

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").

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 properties are located principally in the Barnett Shale and the Raton, Black Warrior and Appalachian basins, 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. The geologists and engineers on our technical staff have significant experience in other productive basins within the continental United States, which will allow us to evaluate and possibly 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. In addition, 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 16% of our segment margin for the year ended December 31, 2013. Additionally, our natural gas, crude oil and NGL production was hedged approximately 73% on an equivalent basis for the year ended December 31, 2013. As of December 31, 2013, we have approximately 209 Bcfe of hedge positions on our natural gas, crude oil and NGL production for 2014 through 2018.

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. Further, we receive an incremental equity interest in each well, for which we do not make any corresponding capital contribution. Consequently, our economic interest in each well is significantly greater than our proportional contribution to the total cash costs which enhances our overall rate of return. Additionally, we 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:

Expand operations through strategic acquisitions. We continually evaluate opportunities to expand our operations through acquisitions of developed and undeveloped properties or companies that will generate attractive risk adjusted expected rates of return and increase our cash available for distribution. Our acquisitions have been characterized by long-lived production, relatively low decline rates and predictable production profiles, as well as relatively low-risk development opportunities. We will continue to seek strategic opportunities in our current areas of operation, as well as other regions of the United States.

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 strategy of increasing our natural gas and oil production through our sponsorship of our Drilling Partnerships as well as drilling wells directly to exploit our acreage opportunities provides us with enhanced economic returns. For the five year period ended December 31, 2013, we raised over $0.9 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. We expect that the fee revenue we generate with respect to fees paid by the Drilling Partnerships to us for partnership management will add stability to our revenue and cash flows. Furthermore, the carried interests and fees we earn reduce the net investment in our drilling program and therefore enhance our rates of return on investment.

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, 2013.

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.

Subsequent Event

GeoMet Acquisition. On February 13, 2014, we entered into a definitive asset purchase and sale agreement to acquire certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for approximately $107.0 million in cash with an effective date of January 1, 2014, subject to certain purchase price adjustments. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia. The closing of the acquisition is subject to certain closing conditions, including a vote by GeoMet's stockholders to approve the transaction.

Recent Developments

EP Energy Acquisition. On July 31, 2013, we completed the acquisition of certain assets from EP Energy, a wholly-owned subsidiary of EP Energy, LLC, and EPE Nominee Corp. Pursuant to the purchase and sale agreement, we acquired certain assets from EP Energy for approximately $709.6 million in cash, net of purchase price adjustments. The purchase price was funded through borrowings under our revolving credit facility, the issuance of our 9.25% Senior Notes, the issuance of 14,950,000 common limited partner units, and the issuance of our newly created Class C convertible preferred units. 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.

Geographic and Geologic Overview

Through December 31, 2013, 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. As of December 31, 2013, we had an interest in approximately 435 Barnett Shale wells, and approximately 115,000 acres prospective for the Barnett Shale. 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 400 feet. As of December 31, 2013, we had an interest in approximately 185 Marble Falls wells. Approximately 75,000 acres of our 115,000 acres prospective for the Barnett Shale are also prospective for the Marble Falls.

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 15 to 400 feet. As of December 31, 2013, we had an interest in approximately 272 Marcellus Shale wells, consisting of 229 vertical wells and 43 horizontal wells. As of December 31, 2013, we drilled, completed and began producing eight new horizontal Marcellus Shale wells in northeastern Pennsylvania, all of which were developed through our partnership management business. Also as of December 31, 2013, approximately 2,450 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 (NYSE: CVX; "Chevron").

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, 2013, we had drilled seven horizontal Utica-Point Pleasant wells, completed five and placed five wells into production. As of December 31, 2013, we had approximately 2,700 net undeveloped acres prospective for the Utica Shale in Columbiana, Trumbull and Stark counties in Ohio. In addition, we currently have an interest in approximately 2,500 wells in Ohio and operate three field offices which we intend to use for future Utica Shale development.

Coal-Bed Methane. Our coal-bed methane developments are diversified across two well-known coal-bed methane producing areas: the Raton and Black Warrior basins. As of December 31, 2013, we had more than 480,000 net undeveloped acres prospective for coal-bed methane. Also as of December 31, 2013, we operated 1,839 wells and had an interest in another 707 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, 2013, we operated 972 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 Pennsylvania 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, 2013, we operated 867 wells and had an interest in an additional 707 wells at the Black Warrior asset.

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-aged 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, 2013, we had an interest in approximately 35 Hunton wells. As of December 31, 2013, we had drilled 27 Mississippi Lime horizontal wells, of which 24 were completed and producing. As of December 31, 2013, had have identified an additional 144 horizontal Mississippi Lime locations across our over 16,000 net acre leaseholds.

Gas and Oil Production

Production Volumes

Currently, our natural gas, crude oil and NGL production operations are focused in various shale 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 certain Drilling Partnerships proportionate to the value of our coinvestment in it and the value of the acreage we contribute to it, approximately 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, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
Production per day:[(1)(2)]			
Natural gas (Mcfd)	158,886	69,408	31,403
Oil (Bpd)	1,329	330	307
Natural gas liquids (Bpd)	3,473	974	444
Total (Mcfed)	187,701	77,232	35,912

(1) “Mcfd” represents thousand cubic feet per day; “Mcfed” represents thousand cubic feet equivalents per day; and “Bpd” represents barrels and barrels per day.

(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

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, 2013, 2012 and 2011, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Years Ended December 31,		
	2013	2012	2011
Production revenues (in thousands):			
Natural gas revenue	$186,229	$70,151	$49,096
Oil revenue	44,160	11,351	10,057
Natural gas liquids revenue	36,394	11,399	7,826
Total revenues	$266,783	$92,901	$66,979
Average sales price:			
Natural gas (per Mcf):			
Total realized price, after hedge[1]	$3.47	$3.29	$4.98
Total realized price, before hedge[1]	$3.25	$2.60	$4.53
Oil (per Bbl):			
Total realized price, after hedge	$91.01	$94.02	$89.70
Total realized price, before hedge	$95.88	$91.32	$89.07
Natural gas liquids (per Bbl) total realized price:	$28.71	$31.97	$48.26
Production costs (per Mcfe):			
Lease operating expenses[2]	$1.09	$0.82	$1.09
Production taxes	0.18	0.12	0.10
Transportation and compression	0.24	0.24	0.43
Total	$1.50	$1.19	$1.61

(1) 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 $3.21 per Mcf ($2.99 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, 2013, 2012 and 2011, respectively.

(2) 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 $1.01 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, 2013, 2012 and 2011, respectively.

Partnership Management Business

We generally fund our drilling activities through sponsorship of tax-advantaged Drilling Partnerships. Accordingly, the amount of development activities we undertake depends in part upon our ability to obtain investor subscriptions to the partnerships. We generally structure our Drilling Partnerships so that, upon formation of a partnership, we coinvest in and contribute leasehold acreage to it, enter into drilling and well operating agreements with it and become its managing general partner. 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. We receive an interest in the Drilling Partnerships proportionate to the amount of capital and the value of the leasehold acreage that we contribute, which interest generally approximates 30% of the overall capitalization in a particular partnership.

Over the last five years, we raised over $0.9 billion 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. We recognize revenues from drilling operations on the percentage-of-completion method as the wells are drilled, rather than when funds are received.

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
2013	$150.0	$ 92.3	$242.3
2012	127.1	54.4	181.5
2011	141.9	28.3	170.2
2010[(1)]	149.3	53.4	202.7
2009	353.4	97.5	450.9
Total	$921.7	$ 325.9	$1,247.6

(1) Does not include funds raised for a fall 2010 drilling program, which was cancelled due to the announcement of the acquisition of the Transferred Business in November 2010 (see "Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations").

As managing general partner of our Drilling Partnerships, we receive the following 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 well;

- Administration and oversight. For each well drilled by a Drilling Partnership, we typically receive a fixed fee between $100,000 and $400,000, depending on the type of well drilled. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of $75 for the life of the well. Because we coinvest in the partnerships, the net fee that we receive is reduced by our proportionate interest in the well;

- Well services. Each Drilling Partnership pays us a monthly per well operating fee, currently $1,000 to $2,000, for the life of the well. Because we coinvest in the Drilling Partnerships, the net fee that we receive is reduced by our proportionate interest in the wells; and

- Gathering. Each royalty owner, Drilling Partnership and certain other working interest owners pay us a gathering fee, which in general is 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 that were formed after January 2012, approximately 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 $9,400 in the year in which the investor invests. For our Drilling Partnerships that were formed prior to January 2012, approximately 85% to 90% of the subscription proceeds received was used to pay 100% of the partnership's intangible drilling costs.

Within our Drilling Partnerships, we have agreed to subordinate a portion of our share of production revenues, net of corresponding production costs, to the investor partners until the partners have received specified returns, typically 10% to 12% per year, over a specific period, typically the first five to eight years, as stipulated within the individual investor partnership agreement.

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, 2013, 2012 and 2011.

	Years Ended December 31,		
	2013	2012	2011
Gross wells drilled	103	105	160
Our share of gross wells drilled[(1)]	66	42	31

(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.

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 our operated wells.

As of December 31, 2013, we had the following ongoing drilling activities:

	Gross			Net		
	Spud	Total Depth	Completed	Spud	Total Depth	Completed
Mississippi Lime – Horizontal	8	3	—	2	1	—
Utica – Horizontal	1	2	—	1	1	—
Marble Falls – Vertical	1	3	6	1	2	4

Hydrocarbon property 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 western 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 Shale and Marble Falls plays), both states where we have acquired substantial acreage positions, royalties are commonly in the 15-20% range, resulting in net revenue interests to us in the 80-85% range.

In the Texas Barnett Shale, 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 production area and pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline, Transco Leidy Line;
- 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; 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 produced 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 charges. 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, 2013, Enterprise Products Operating LLC, Chevron and Empire Pipeline Corporation accounted for approximately 19%, 11%, and 10% 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 marketing. 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 Production 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 our market. Our Utica production in Ohio is gathered by both UEO Midstream and Blue Racer Midstream for delivery to UEO’s Kensington Processing plant. Residue gas and NGLs are sold locally.

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. Black Warrior Basin production is gathered by us and Southcross Alabama pipeline for delivery to Sonat.

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 they receive. That POP amount is approximately 95%. The remaining 5% and a $0.32 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. During the years ended December 31, 2013 and 2012, we faced no shortage of these goods and services. Over the past several years, we and other oil and natural gas companies have experienced higher 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 demand for natural gas and oil.

We maintain a Pennsylvania Operating Services Agreement, pursuant to which a subsidiary of Chevron provides us (including Drilling Partnerships which we manage) with certain operational services including, among other things, gas volumetric control, measurement and balancing services and water disposal services with respect to certain wells in Pennsylvania in exchange for specified fees. We will indemnify the provider against all claims and liabilities arising out of its provision of services under this agreement. We may terminate the agreement or any portion of the services provided under the agreement at any time, and either party may terminate the agreement following an uncured material breach of the agreement by the other party. The initial term of this agreement expired on February 17, 2014. The agreement continues through the end of August 2014 and may continue from month to month thereafter, subject to the right of either party to cancel the agreement.

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. During the years ended December 31, 2013, 2012 and 2011, we did not experience problems in selling our natural gas, oil and NGLs, although prices have varied significantly during those periods.

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 have typically received the majority of funds from Drilling Partnerships during the fourth calendar quarter.

Environmental Matters and Regulation

Overview. Our operations are subject to comprehensive and stringent federal, state and local laws and regulations governing, among other things, where and how we drill wells, how we handle waste from our operations and the discharge of materials into the environment. Our operations will be subject to the same environmental laws and regulations as other companies in the natural gas and oil industry. Among other requirements and restrictions, these laws and regulations may:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment and water treatment facilities;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling, completion and production activities;
- limit or prohibit drilling activities on certain land;

- require 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;

- impose substantial liabilities for pollution resulting from our operations; and

- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

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 substantially comply with all currently applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict how environmental laws and regulations that may take effect in the future may impact our properties or operations. For the three-year period ended December 31, 2013, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities. We are not aware of any environmental issues or claims that will require material capital expenditures during 2014, or that will otherwise have a material impact on our financial position or results of operations.

Environmental laws and regulations that could have a material impact on the natural gas and oil exploration and production industry 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 (“NEPA”). NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly impact 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 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 the Resource Conservation and Recovery Act (“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 Environmental Protection Agency (“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.

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 we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes to be significant, any more stringent regulation of natural gas and oil exploitation and production wastes could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. 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 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. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties, and the substances disposed or released on them, may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws 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 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.

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 our operations are in substantial compliance with the requirements of the Clean Water Act.

Air Emissions. The Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through permits and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic and other air pollutants at specified sources. In 2012, specific federal regulations applicable to the natural gas industry were finalized under the New Source Performance Standards

(“NSPS”) program along with National Emissions Standards for Hazardous Air Pollutants (“NESHAP”). These new regulations 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 emission limitations. These regulations may increase the costs of compliance for some facilities, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance. These laws and regulations also apply to entities that use natural gas as fuel, and may increase the costs of compliance of our customers to the point where demand for natural gas is affected. We believe that our operations are in substantial compliance with the requirements of the Clean Air Act.

OSHA and other regulations. We are subject to the requirements of the federal Occupational Safety and Health Act (“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.

Greenhouse gas regulation and climate change. Natural gas contains methane, which is considered to be a greenhouse gas. Additionally, the burning of natural gas produces carbon dioxide, which is also a greenhouse gas. Published studies have suggested that the emission of greenhouse gases may be contributing to global warming. 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 (December 15, 2009). This finding led to the regulation of greenhouse gases under the Clean Air Act. Currently, the EPA has promulgated two rules that will impact our business.

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. 31514 (June 3, 2010). Both the federal preconstruction review program ("Prevention of Significant Deterioration" or "PSD") and the operating permit program ("Title V") 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 Title V operating permits.

Second, the EPA finalized its Mandatory Reporting of Greenhouse Gases rule in 2009, 74 Fed. Reg. 56,260 (October 30, 2009). Subsequent revisions, additions, and clarification rules were promulgated, including a rule specifically addressing the natural gas industry. These rules require 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.

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 discussion 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 that could have an impact on our business.

Finally, as noted above, 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.

Other regulation of the natural gas and oil industry. The natural gas and oil industry is extensively regulated by numerous 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. 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 costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Energy Policy Act of 2005. 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 ("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 ARP's business and operations. For instance, the U.S. EPA published a draft "Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels" ("Draft Diesel Guidance") on May 10, 2012 for public comment through August 23, 2012. In that Draft Diesel Guidance, the EPA asserts SDWA permitting authority over hydraulic fracturing activities that employ the injection of diesel fuel. The EPA submitted its draft guidance to the White House Office of Management and Budget in September 2013. The draft guidance submitted to the White House Office of Management and Budget was not published by the EPA, so it is not clear what changes may have been made to the guidance by the EPA as a result of the comments received during the 2012 public comment period. The EPA has not provided a specific timeframe for the release of the final guidance.

The U.S. Senate and House of Representatives considered legislative bills in the 111th and 112th 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. In 2013, the Frac Act was re-introduced in the 113th Session of Congress. 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 its employees. There are various federal and state environmental and safety requirements for handling sour gas, and we believe we are in substantial compliance with all such requirements.

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

· the location of wells;

· the manner in which water necessary to develop wells is accessed, utilized, managed and disposed of;

· the method of drilling, completing and casing and producing wells;

· the surface use and restoration of properties upon which wells are drilled;

· the plugging and abandoning of wells; and

· notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of 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 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 natural gas liquids 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 2013, the impact fee for qualifying unconventional horizontal wells spudded during 2013 was $50,000 per well, while the impact fee for unconventional vertical wells was $10,000 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 a fee of $0.000667 per Mcf of gas produced and $.00625 per barrel of crude. New Mexico imposes a severance tax of up to 3.75% of the value of oil and gas produced, a conservation tax equal to 0.19% 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% of oil or gas. Oklahoma imposes a gross production tax of 7% per Bbl of oil, 7% per Mcf of natural gas and a petroleum excise tax of $0.095 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 but not limited to 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 impacts of hydraulic fracturing on drinking water and ground water. The EPA released a progress report on this study on December 21, 2012 that did not present any conclusions, but notes that results will be released in draft form in late 2014 for review by the public and the EPA Science Advisory Board. The Department of Interior’s Bureau of Land Management published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands on May 24, 2013, and a final rule is expected to be issued in 2014.

In addition, state, 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, 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.

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. Approximately 640 ATLS employees provide direct support to our operations. Some of the officers of our general partner may spend a substantial amount of time managing the business and affairs of ATLS 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”. 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.

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. 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

If commodity prices decline significantly, our cash flow from operations will decline.

Our revenue, profitability and cash flow substantially depend upon the prices and demand for natural gas and oil. The natural gas, natural gas liquids, and oil markets are very volatile, and a drop in prices can significantly affect our financial results and impede our growth. Changes in natural gas, natural gas liquids and oil prices will have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas, natural gas liquids and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, natural gas liquids or oil, market uncertainty and a variety of additional factors that are beyond our control, such as:

· the level of domestic and foreign supply and demand;

· the price and level of foreign imports;

· the level of consumer product demand;

· weather conditions and fluctuating and seasonal demand;

· overall domestic and global economic conditions;

· political and economic conditions in natural gas and oil producing countries, including those in the Middle East and South America;

- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the impact of the U.S. dollar exchange rates on natural gas and oil prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental relations, regulations and taxation;
- the impact of energy conservation efforts;
- the cost, proximity and capacity of natural gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

In the past, the prices of natural gas, natural gas liquids and oil have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2013, the NYMEX Henry Hub natural gas index price ranged from a high of $4.46 per MMBtu to a low of $3.11 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $110.53 per Bbl to a low of $86.68 per Bbl. Between January 1, 2014 and February 25, 2014, the NYMEX Henry Hub natural gas index price ranged from a high of $6.15 per MMBtu to a low of $4.01 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $103.31 per Bbl to a low of $91.66 per Bbl.

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.

Shortages of drilling rigs, equipment and crews, or the costs required to obtain the foregoing in a highly competitive environment, could impair our operations and results.

Increased demand for drilling rigs, equipment and crews, due to increased activity by participants in our primary operating areas or otherwise, can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues.

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 in these areas.

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.

The natural gas and oil industry is capital intensive. If we are unable to obtain sufficient capital funds on satisfactory terms with capital raised through equity and debt offerings, cash flow from operations, bank borrowings and the Drilling Partnerships, 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.

Our cash distribution policy limits our ability to grow.

Because we distribute our available cash 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. If we issue additional common units or incur debt to fund acquisitions and expansion and 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 increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units.

Significant physical effects of climatic 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, 2013, Enterprise Products Operating LLC, Chevron, and Empire Pipeline Corporation accounted for approximately 19%, 11% and 10% 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, 2013, leases covering approximately 22,558 of our 911,354 net undeveloped acres, or 2.5%, are scheduled to expire on or before December 31, 2014. An additional 4.0% and 0.5% are scheduled to expire in each of the years 2015 and 2016, respectively. 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, which would reduce our cash flows from operations.

Drilling for and producing natural gas 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 can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- 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;
- environmental accidents such as gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment or oil leaks, 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, 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.

Although we maintain insurance against various losses and liabilities arising from our operations, insurance against all operational risks are 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 reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our natural gas 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.

A decrease in natural gas 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. Accordingly, further declines in the price of natural gas 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.

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 deeded hedges for accounting purposes because they require firm delivery of natural gas and are considered normal sales of natural gas. We general limit these arrangements to smaller quantities than those 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 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. If, among other circumstances, production is substantially less than expected, the counterparties to our futures contracts fail to perform under the contracts or a sudden, unexpected event materially changes commodity prices, we may be exposed to the risk of financial loss. 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.

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 Dodd-Frank Wall Street Reform and Consumer Protection Act is intended to change fundamentally the way swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which most swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. These statutory requirements must be implemented through regulation, primarily through rules adopted by the Commodities Futures Trading Commission ("CFTC"). Many market participants will be newly regulated as swap dealers or major swap participants, with new regulatory capital requirements and other regulations that impose business conduct rules and mandate how they hold collateral or margin for swap transactions. All market participants will be subject to new reporting and recordkeeping requirements. The new regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities. As a commercial end-user which uses swaps to hedge or mitigate commercial risk, rather than for speculative purposes, we are permitted to opt out of the clearing and exchange trading requirements. However, we could be exposed to greater liquidity and credit risk with respect to our hedging transactions if we do not use cleared and exchange-traded swaps. Counterparties to our derivative instruments which are federally insured depository institutions are required to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The 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 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 combined financial position, results of operations and/or cash flows.

The scope and costs of the risks involved in making acquisitions may prove greater than estimated at the time of the acquisition.

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;
- customer or key employee losses at the acquired businesses; and
- the failure to realize expected growth or profitability.

The scope and cost of these 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.

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.

Properties that we acquired in the separation from ATLS or afterward 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.

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 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 the properties included in the acquisitions 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 will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential.

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.

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.

Federal legislation 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:

- New York has imposed a de facto moratorium on the issuance of permits for high volume, horizontal hydraulic fracturing until state administered environmental and public health studies are finalized. The Department of Environmental Conservation (the “NYDEC”), accepted comments on its revised proposal to amend state regulations to address high-volume hydraulic fracturing through January 11, 2013, and NYDEC has not issued final regulations. In October 2012, the NYDEC asked the New York Department of Health (the “NYDH”), to assess the health impacts of high volume hydraulic fracturing. The NYDH has not completed its assessment, nor has not set a deadline by which it will complete its review. New York is not expected to take any final action or make any decision regarding hydraulic fracturing until after the health review is completed by NYDH and the NYDEC, through the environmental impact statement, is satisfied that hydraulic fracturing can be done safely in New York State.

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Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. On February 14, 2012, legislation was passed in Pennsylvania ("2012 Oil and Gas Act") requiring, among other things, disclosure of chemicals used in hydraulic fracturing. To implement the new legislative requirements, on December 14, 2013 the Pennsylvania Department of Environmental Protection ("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. According to PADEP, the conceptual changes would include updates existing requirements regarding containment of regulated substances, waste disposal, site restoration and reporting releases, and it would establish new planning, notice, construction, operation, reporting and monitoring standards for surface activities associated with the development of oil and gas wells. PADEP has also proposed to add new requirements for addressing impacts to public resources, identifying and monitoring orphaned and abandoned wells during hydraulic fracturing activities, and the submitting water withdrawal information necessary to secure a required Water Management Plan.

- In June 2012, Ohio passed legislation that made several significant amendments to the state's oil and gas law, including additional permitting requirements, chemical disclosure requirements, and site investigation requirements for horizontal wells.

- In September 2012, the Texas Railroad Commission approved new proposed regulations relating to the commercial recycling of produced water and/or hydraulic fracturing flowback fluid. In June 2013, the SEC adopted amendments to the Texas Administrative Code regarding casing, cementing, drilling, completion and well control.

- On April 12, 2013, the West Virginia Legislature passed a legislative rule titled “Rules Governing Horizontal Well Development,” which became effective on July 1, 2013. The rule 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 addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. A recent update regarding local land use restrictions in Pennsylvania occurred on December 19, 2013, when the Pennsylvania Supreme Court issued its Robinson Township v. Commonwealth of Pennsylvania ruling, which invalidated a key section of the 2012 Oil and Gas Act that placed limits on the regulatory authority of local governments. While the total impact of the Pennsylvania Supreme Court’s ruling is not clear and will occur over an extended period of time, an immediate impact of the ruling may be increased regulatory impediments and disputes at the local government level. 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 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. After reviewing comments submitted on the draft guidance, which were due by August 23, 2012, the EPA submitted its draft guidance to the White House Office of Management and Budget in September 2013. EPA’s draft guidance submitted to the White House Office of Management and Budget was not published, so it is not clear what changes may have been made to the guidance by EPA as a result of the comments received during the 2012 public comment period. At present, we are not aware of EPA’s timeframe to release the final guidance. 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 environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA issued a progress report regarding the hydraulic fracturing study on December 21, 2012. However, the progress report did not provide any results or conclusions. On December 9, 2013, 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. Research results are expected to be released in draft form in late 2014 for review by the public and the EPA Science Advisory Board. The EPA has not provided an anticipated date for completion of the report after peer review. The EPA is also proposing to issue a draft criteria document updating the water quality criteria for chloride in summer 2014, and a proposed rule regarding effluent limitation guidelines for natural gas extraction from shale gas in 2014. On May 4, 2012, the U.S. Department of the Interior, Bureau of Land Management proposed a rule that includes provisions requiring disclosure of chemicals used in hydraulic fracturing and construction standards for hydraulic fracturing on federal lands. On May 24, 2013, the Bureau of Land Management published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands. The comment period closed on August 23, 2013 and the revised proposed rule drew more than 175,000 comments. A final rule is expected to be issued in 2014.

Certain members of 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 to be released in Spring 2014. These ongoing or 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, but are not limited to, the following: additional permitting requirements, 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, among other potential effects that are not listed here. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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

In August 2012, the EPA published final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards, which we refer to as the NSPS, to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The NSPS require operators, starting in 2015, to reduce VOC emissions from oil and natural gas production facilities by conducting "green completions" for hydraulic fracturing, that is, recovering rather than venting the gas and natural gas liquids that come to the surface during completion of the fracturing process. The NSPS also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production equipment. In addition, effective in 2012, the rules establish new notification requirements before conducting hydraulic fracturing and more stringent leak detection requirements for natural gas processing plants. The NSPS became effective October 15, 2012 and will likely require a number of modifications to our operations, including the installation of new equipment. Compliance with the new rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

States are also proposing more stringent requirements in air permits for well sites and compressor stations. For example, Pennsylvania recently revised its list of sources exempt from air permitting requirements such that previously exempted types of sources associated with oil and gas exploration and production now are required to: (1) obtain an air permit or (2) satisfy specific requirements (emission limits, monitoring and recordkeeping) in order to claim the permit exemption. In conjunction with this proposal, Pennsylvania has finalized revisions to its General Permit for Natural Gas Production Facilities to impose additional and more stringent requirements and emission limits. Ohio is also considering revising its current General Permit for Natural Gas Production Operations to cover emissions from completion activities.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for our services.

Both houses of U.S. Congress have actively considered legislation to reduce emissions of greenhouse gases, and almost half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. The adoption of any legislation or regulations that limits 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, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases may present a danger to public health and the environment because emissions of such gases are contributing to the warming of the earth's atmosphere and other climate changes, the EPA has adopted regulations under existing provisions of the Clean Air Act that require entities that produce certain gases to inventory, monitor and report such gases. On November 30, 2010, the EPA published a final greenhouse gas emissions reporting rule relating to natural gas processing, transmission, storage, and distribution activities, which requires reporting of emissions on an annual basis starting with emissions occurring in 2011. Additionally, in 2010, the EPA issued rules to regulate greenhouse gas emissions through traditional major source construction and operating permit programs. The EPA confirmed the permitting thresholds established in the 2010 rule in July 2012. These permitting programs require consideration of and, if deemed necessary, implementation of best available control technology to reduce greenhouse gas emissions. As a result, our operations could face additional costs for emissions control and higher costs of doing 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 requires the development, submission and approval of a Water Management Plan before hydraulically fracturing an unconventional well. The requirements of these plans continue to be modified by proposed amendments to state regulations and PADEP's policies and guidance. For Pennsylvania operations located in the Susquehanna River Basin, the Susquehanna River Basin Commission ("SRBC") regulates consumptive water uses, water withdrawals, and the diversions of water into and out of the Susquehanna River Basin, and specific SRBC 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 our water needs for a particular project, we will be required to develop a Water Conservation Plan and obtain a withdrawal permit for that project.

Our ability to collect and dispose of water will affect our production, and potential increases in the cost of water 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 produced water, 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 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, Pennsylvania implemented an impact fee for unconventional wells drilled in the Commonwealth. An unconventional gas well is a well that is drilled into an unconventional formation, which would include the Marcellus shale. The impact fee, which changes from year to year, is computed using the prior year's trailing 12 month NYMEX natural gas price and is based upon a tiered pricing matrix. For example, based upon natural gas prices for 2013, the impact fee for qualifying unconventional horizontal wells spudded during 2013 was $50,000 per well and the impact fee for unconventional vertical wells was $10,000 per well. The impact fee is due by April 1 of the year following the year that a horizontal unconventional well is spudded or a vertical unconventional well is put into production. The fee will continue for 15 years for a horizontal unconventional well and 10 years for a vertical unconventional well. We estimate that the impact fee for our wells including the wells in our Drilling Partnerships will be in excess of $1.7 million for the year ended December 31, 2013.

Ohio Governor John Kasich has proposed a severance tax on gas, oil and natural gas liquids produced from high-volume producing formations that are recovered through hydraulic fracturing. Under the proposed tax plan, oil and natural gas liquids recovered through hydraulic fracturing in the Utica and Marcellus shales would be taxed at 1.5% of annual gross sales in the first year and 4% per year for each year thereafter. Natural gas would be taxed yearly at 1% of gross sales. The proposed plan also levies a $25,000 up front impact fee for each well drilled in the state. The Governor's proposal was rejected by the General Assembly, and not included in the State's biennial budget bill (H.B. 59) adopted on June 30, 2013. The General Assembly is considering an alternative bill, H.B.375, introduced on December 4, 2013, that would significantly change Ohio's severance tax on the production of oil and gas. The tax on the production of oil and gas from conventional wells would be lowered to $0.10/Bbl oil and $0.015/Mcf natural gas. The tax on the production of oil and gas from unconventional wells would become 1% of net proceeds at the wellhead for both oil and gas for the first five years of production, increasing to 2% thereafter, but dropping again to 1% when production falls below 17 barrels of oil per day per quarter or 100 Mcf gas per day per quarter.

President Obama's budget proposals for 2014 included proposed provisions with significant tax consequences. If enacted, U.S. tax laws could be amended to eliminate certain deductions for drilling, exploration and development and the mandatory funding of certain public lands and research and development of transportation alternatives.

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 oil and gas enforcement activities. For example, in 2011, 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. 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 we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could inhibit our ability to develop our respective properties. Additionally, the natural gas and oil regulatory environment could 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 General Assembly approved legislation in February 2012, known as the Oil and Gas Act, that imposes significant, costly requirements on the natural gas industry, including the imposition of increased bonding requirements and impact fees for gas wells, based on the price of natural gas and the age of the well. Proposed regulations associated with this legislation have been released for public comment by the PADEP and, if finalized, will impact how natural gas operations are conducted in Pennsylvania. Similarly, West Virginia promulgated regulations associated with its existing Horizontal Well Control Act and is signaling that additional regulations are on the horizon. We may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and 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 $150.0 million, $127.1 million and $141.9 million in 2013, 2012 and 2011, 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 2014 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 years ended December 31, 2013, 2012 and 2011, $9.6 million, $6.3 million and $4.0 million, respectively, of our revenues, net of corresponding production costs, were subordinated, which reduced our cash distributions received from the Drilling Partnerships.

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.

Covenants in our credit facility restrict our business in many ways.

Our credit facility contains 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 credit facility requires 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. A breach of any of these covenants could result in a default under our credit facility. Upon the occurrence of an event of default, the lenders under the credit facility could elect to declare all amounts outstanding immediately due and payable and 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 facility. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facility and our other liabilities. Our borrowings under our credit facility 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.

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.

Our operations are affected by the financial markets and related effects in the global financial system. The consequences of an economic recession and the effects of the financial crisis include a lower level of economic activity and increased volatility in energy prices. This may result in a decline in energy consumption and lower market prices for oil and natural gas and has previously resulted in a reduction in drilling activity in our service areas. Any of these events may adversely affect our revenues and ability to fund capital expenditures and, in the future, may impact the cash that we have available to fund our operations, pay required debt service on our credit facility and make distributions to our unitholders.

Potential instability in the financial markets, as a result of recession or otherwise, can cause volatility in the markets and may 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 or to respond to competitive pressures, any of which could negatively impact our business.

A 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 affects 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 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 ATLS. These allocations were based on what we and ATLS 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.

Estimates of the 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 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 properties also will be affected by factors such as:

· actual prices we receive for natural gas;

· 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 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.

Risks Relating to the Ownership of Our Common Units

If the unit price declines, our common unitholders could lose a significant part of their investment.

The market price of our common 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;
- 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 units.

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

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

At December 31, 2013, ATLS owned approximately 20.96 million common and 3.75 million preferred limited partner units, representing approximately 36.9% limited partner ownership interest in us. ATLS 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 ATLS and its affiliates. These registration rights allow ATLS, our general partner and their affiliates to request registration of their common units and to include any of those units in a registration of other securities by us. If ATLS and its affiliates were to sell a substantial portion of their units, it could reduce the market price of our outstanding common units.

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

Like all equity investments, an investment in our common units is subject to 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 common units resulting from investors seeking other investment opportunities may cause the trading price of our common 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 future operations, future capital expenditures, 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 depends primarily on our cash flow and not solely on profitability.

The amount of cash that we have available for distribution 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 credit facility have restrictions and financial covenants that may restrict our business and financing activities and 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 revolving credit facility restricts, among other things, our ability to incur debt and pay distributions, and requires us to comply with customary financial covenants and specified financial ratios. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our revolving credit facility that are not cured or waived within the specified time periods, a significant portion of our indebtedness may become immediately due and payable, and we will be prohibited from making distributions to our unitholders. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our revolving credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our revolving credit facility, the lenders could seek to foreclose on our assets.

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

Pursuant to our partnership agreement, ATLS and our general partner receive 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 common units in any fiscal quarter, our unitholders are not entitled to receive distributions for such prior periods in the future.

Our distributions to our unitholders are not cumulative. Consequently, if we do not pay distributions on our common units with respect to any quarter, our unitholders are not entitled to such payments in the future.

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 ATLS, our general partner, their respective affiliates, their transferees and persons who acquire common units directly from us with the prior approval of our general partner, 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 common 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 common units of any holder that is not an eligible citizen or fails to furnish the requested information.

Common 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 common 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 chosen by ATLS, the owner of 100% of the equity of our general partner. The board of directors of ATLS’s general partner is elected by the unitholders of ATLS. 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 the company, the price at which the common units trade could be diminished.

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. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and thereby influence the decisions made by the board of directors and officers.

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, without unitholder approval, which would dilute common 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 units that we may issue at any time without the approval of our common 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. The issuance by us of additional units or other equity interests of equal or senior rank will have the following effects:

· our common 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 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 New York Stock Exchange (“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, neither we or our general partner have a nominating/governance committee or a compensation committee, and our general partner does not have a majority of independent directors.

In addition, NYSE rules requiring that shareholder 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 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 common units, 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 the common units 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 common units at an undesirable time or price. You may also incur a tax liability upon a sale of your common units.

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

The credit and risk profiles of our general partner and its owner may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our general partner and indirect owner 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 and its owners, including the degree of their financial leverage and their dependence on cash flow from us to service their indebtedness.

Your 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. You could be liable for any and all of our obligations as if you 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

- your 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.

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.

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

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

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, West Virginia and Wyoming. 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.

Risks Relating to Our Ongoing Relationship with ATLS and its Affiliates

ATLS owns common and preferred limited partner units representing an approximate 36.9% limited partner ownership interest. Therefore, ATLS possesses significant influence on all matters submitted to a vote of our unitholders.

At December 31, 2013, ATLS owned approximately 20.96 million common and 3.75 million preferred limited partner units representing an approximate 36.9% limited partner ownership interest in us. Accordingly, ATLS 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, ATLS owns all of the equity of our general partner and 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;
- compensation and benefit programs and other human resources policy decisions;
- the payment of dividends on our units; and
- determinations with respect to our tax returns.

ATLS owns and controls our general partner, which has the authority to conduct our business and manage our operations. ATLS may have conflicts of interest, which may permit it to favor its own interests to our unitholders' detriment.

ATLS owns and controls our general partner. Conflicts of interest may arise between ATLS and its affiliates, including our general partner, 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 ATLS 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, such as ATLS, 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.

ATLS and other 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 our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership interest in us. Affiliates of our general partner, however, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. ATLS and its affiliates may make investments and acquisitions that may include entities or assets that we would have been interested in acquiring. In addition, members of management of ATLS, some of whom may also participate in the management of our general partner, have substantial experience in the natural gas and oil business.

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

Our partnership agreement provides that:

- subject to any contractual provision to the contrary, ATLS has 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 ATLS 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, ATLS 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 ATLS 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 affiliates of our general partner and result in less than favorable treatment of us.

Certain of the officers and directors of our general partner may have actual or potential conflicts of interest because of their positions with ATLS.

Certain of the directors and officers of our general partner, including our Chairman, Chief Executive Officer, Vice Chairman, President, Chief Financial Officer, Chief Accounting Officer and Chief Legal Officer, have positions with ATLS or its general partner. In addition, such directors and officers may own ATLS common units, options to purchase ATLS common units or other ATLS equity awards. The individual holdings of ATLS common units, options to purchase common units of ATLS or other equity awards may be significant for some of these persons compared to these persons' total assets. Their position at ATLS and the ownership of any ATLS equity or equity awards creates, or may create the appearance of, conflicts of interest when these expected directors and officers are faced with decisions that could have different implications for ATLS 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, 2013. 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 Wright & Company, Inc., an independent third-party reserve engineer. We have adjusted these estimates to reflect the settlement of asset retirement obligations on gas and oil properties. A summary of the reserve report related to our estimated proved reserves at December 31, 2013 is included as Exhibit 99.1 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, 2013 and 2012, and are listed below as of the dates indicated:

	December 31, 2013	December 31, 2012
Unadjusted Prices[(1)]		
Natural gas (per Mcf)	$3.67	$2.76
Oil (per Bbl)	$96.78	$94.71
Natural gas liquids (per Bbl)	$30.10	$33.91
Average Realized Prices, Before Hedge[(1) (2)]		
Natural gas (per Mcf)	$3.25	$2.53
Oil (per Bbl)	$95.88	$92.26
Natural gas liquids (per Bbl)	$29.43	$31.97

(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, 2013 and 2012. Including the effect of this subordination, the average realized sales price was $3.00 per Mcf before the effects of financial hedging and $2.08 per Mcf before the effects of financial hedging for years ended December 31, 2013 and 2012, 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, 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 37 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 15 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 the Chief Operating Officer and 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 Wright & Company, Inc. in preparing its reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, 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 reserves at constant temperature and pressure. A change in either of these factors can affect the measurement of natural gas 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,	
	2013	2012
Proved reserves:		
Natural gas reserves (MMcf)[(1)]:		
Proved developed reserves	727,927	338,655

Proved undeveloped reserves[2]	236,907	235,119
Total proved reserves of natural gas	964,834	573,774
Oil reserves (MBbl)[1]:		
Proved developed reserves	3,458	3,400
Proved undeveloped reserves[2]	11,530	5,469
Total proved reserves of oil	14,988	8,869
NGL reserves (MBbl):		
Proved developed reserves	7,676	7,885
Proved undeveloped reserves[2]	11,281	8,177
Total proved reserves of NGL	18,957	16,062
Total proved reserves (MMcfe)[1]	1,168,507	723,359
Standardized measure of discounted future cash flows (in thousands)[3]	$1,039,192	$623,676

(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 generally approximates 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, 2013 and 2012 calculations of standardized measure, which is, therefore, the same as the PV-10 value.

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, 2013, we had 598 PUD locations totaling approximately 373,773 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.

Historically, the primary focus of our drilling operations has been in the Appalachian Basin. We subsequently completed acquisitions in the Barnett Shale/Marble Falls play, the Mississippi Lime play and the Raton Basin, Black Warrior Basin and the County Line area of Wyoming during the years ended December 31, 2013 and 2012, we will continue to integrate these areas and increase our proved reserves through organic leasing as well as drilling on our existing undeveloped acreage.

Our organic growth will focus on expanding our acreage position in our target areas, including our operations in the Marcellus Shale, Utica Shale, Barnett Shale/Marble Falls play, Mississippi Lime play, Raton and Black Warrior basins and the County Line area of Wyoming. Through our previous drilling in these regions, as well as our geologic analysis of these areas, we are expecting these expansion locations to have a significant impact on our proved reserves.

Changes in PUDs. Changes in PUDS that occurred during the year ended December 31, 2013 were due to the following:

- addition of approximately 158.6 Bcfe due to our drilling activity in the Marcellus Shale, Utica Shale, Mississippi Lime and Marble Falls play;

- addition of approximately 34.6 Bcfe due to our acquisition of acreage in the Raton and Black Warrior Basins; partially offset by

- negative revisions of approximately 77.5 Bcfe in PUDs primarily due to the reduction of our five year drilling plans in the Barnett Shale and pricing scenario revisions.

Development Costs. Costs incurred related to the development of PUDs were approximately $103.3 million, $83.5 million and $40.5 million for the years ended December 31, 2013, 2012 and 2011, respectively. During the years ended December 31, 2013, 2012 and 2011, approximately 117.2 Bcfe, 71.5 Bcfe and 8.1 Bcfe of our reserves, respectively, were converted from PUDs to proved developed reserves. As of December 31, 2013, there were no PUDs that had remained undeveloped for five years or more.

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, 2013. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, 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	7,681	3,767
Oil wells	495	355
Total	8,176	4,122
Coal-bed Methane(3):		
Gas wells	2,955	2,172
Oil wells	—	—
Total	2,955	2,172
Barnett/Marble Falls:		
Gas wells	569	470
Oil wells	52	35
Total	621	505
Mississippi Lime/Hunton:		
Gas wells	66	47
Oil wells	—	—
Total	66	47
Other operating areas(4):		
Gas wells	782	240
Oil wells	2	1
Total	784	241
Total:		
Gas wells	12,053	6,696
Oil wells	549	391
Total	12,602	7,087

(1) Includes our proportionate interest in wells owned by 86 Drilling Partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 610 wells.

(2) There were no exploratory wells drilled during the years ended December 31, 2013, 2012 and 2011; there were no gross or net dry wells within our operating areas during the year ended December 31, 2013. During the year ended December 31, 2012, there were 8 gross (3 net) dry wells drilled in the Niobrara shale. During the year ended December 31, 2011, there were 14 gross (5 net) dry wells drilled in the Niobrara shale.

(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 County Line area of Wyoming.

(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, 2013. 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)
Pennsylvania	152,297	75,439	2,918	2,918
New Mexico	124,862	124,862	447,713	447,713
Ohio(5)	110,297	100,044	103,313	100,870
Texas	86,097	59,489	69,259	57,532
Alabama	57,097	51,897	39,994	37,173
Indiana	32,969	24,533	134,084	73,086
Wyoming	29,737	5,677	830	156
Colorado	24,851	18,242	20,278	20,278
Tennessee	20,463	8,471	148,103	145,923
Oklahoma	19,366	15,737	3,325	2,012
New York	13,254	11,965	22,278	20,256
Other	3,291	675	3,625	3,437
Total	674,581	497,031	995,720	911,354

(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 2,735 acres under new leases taken in Ohio that remain undeveloped.

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, 2013. As of December 31, 2013, leases covering approximately 22,558 of our 911,354 net undeveloped acres, or 2.5%, are scheduled to expire on or before December 31, 2014. An additional 4.0% and 0.5% are scheduled to expire in each of the years 2015 and 2016, respectively.

We believe that we hold good and indefeasible title related to producing properties, in accordance with standards generally accepted in the natural gas 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 natural gas 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 12".

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 began trading on March 14, 2012 and are listed on the New York Stock Exchange ("NYSE") and are traded under the ticker symbol "ARP". At the close of business on February 25, 2014, the closing price of our common limited partner units was $21.30, and there were 201 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, 2013 and 2012:

	High	Low	Cash Distribution per Common Limited Partner Declared(1)
Year ended December 31, 2013:			
Fourth quarter	$21.65	$18.78	$ 0.58
Third quarter	$22.77	$18.30	$ 0.56
Second quarter	$25.71	$20.68	$ 0.54
First quarter	$25.10	$21.82	$ 0.51
Year ended December 31, 2012:			
Fourth quarter	$26.78	$21.23	$ 0.48
Third quarter	$28.23	$24.08	$ 0.43
Second quarter	$28.89	$23.15	$ 0.40
First quarter(2)	$31.97	$21.51	$ 0.12

(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.
(2) Our common units began trading on March 14, 2012. The highest and lowest sales prices reflected for the first quarter 2012 are based on the sales prices during the partial quarter from March 14, 2012 through March 31, 2012. The distribution was based on the partial quarter from March 14, 2012 through March 31, 2012.

We have a cash distribution policy under which we distribute, within 45 days after the end of each quarter, all of our available cash (as defined in the partnership agreement) for that quarter to our common and preferred unitholders and general partner. 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 transferred to us on March 5, 2012. The consolidated statements of operations data for the years ended December 31, 2013 and 2012 and the consolidated balance sheet data as of December 31, 2013 and 2012, have been derived from our audited consolidated financial statements included in “Item 8: Financial Statements and Supplementary Data”. The consolidated statement of operations data for the year ended December 31, 2011 has been derived from Atlas Energy E&P Operations’ audited consolidated financial statements included in “Item 8: Financial Statements and Supplementary Data”. The consolidated statements of operations data for the years ended December 31, 2010 and 2009 and the consolidated balance sheet data as of December 31, 2011, 2010 and 2009 are 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/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/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,				
	2013	2012	2011	2010	2009
	(in thousands, except per unit data)				
Statement of operations data:					
Revenues:					
Gas and oil production	$ 266,783	$ 92,901	$ 66,979	$ 93,050	$ 112,979
Well construction and completion	167,883	131,496	135,283	206,802	372,045
Gathering and processing	15,676	16,267	17,746	14,087	18,839
Administration and oversight	12,277	11,810	7,741	9,716	15,554
Well services	19,492	20,041	19,803	20,994	17,859
Other, net	(14,456)	(4,886)	(30)	—	—
Total revenues	467,655	267,629	247,522	344,649	537,276
Costs and expenses:					
Gas and oil production	97,237	26,624	17,100	23,323	25,557
Well construction and completion	145,985	114,079	115,630	175,247	315,546
Gathering and processing	18,012	19,491	20,842	20,221	25,269
Well services	9,515	9,280	8,738	10,822	9,330
General and administrative	78,063	69,123	27,536	11,381	15,832
Chevron transaction expense	—	7,670	—	—	—
Depreciation, depletion and amortization	136,763	52,582	30,869	40,758	43,712
Asset impairment	38,014	9,507	6,995	50,669	156,359
Total costs and expenses	523,589	308,356	227,710	332,421	591,605
Operating income (loss)	(55,934)	(40,727)	19,812	12,228	(54,329)
Interest expense	(34,324)	(4,195)	—	—	—
Gain (loss) on asset sales and disposal	(987)	(6,980)	87	(2,947)	—
Net income (loss)	(91,245)	(51,902)	19,899	9,281	(54,329)
Preferred limited partner dividends	(11,992)	(3,063)	—	—	—
Net income (loss) attributable to owner's interest, common limited partners and the general partner	$ (103,237)	$ (54,965)	$ 19,899	$ 9,281	$ (54,329)

Balance sheet data (at period end):					
Property, plant and equipment, net	$ 2,120,818	$ 1,302,228	$ 520,883	$ 508,484	$ 503,386
Total assets	2,343,800	1,498,952	702,366	649,232	690,603
Total debt, including current portion	942,334	351,425	—	—	—
Total equity	1,067,291	862,006	457,175	381,882	351,586
Cash flow data:					
Net cash provided by operating activities	$ 122,900	$ 16,486	$ 71,437	$ 60,586	$ 192,201
Net cash used in investing activities	(984,554)	(644,278)	(47,509)	(92,423)	(98,393)
Net cash provided by (used in) financing activities	840,294	596,272	30,780	31,837	(93,808)
Capital Expenditures	(263,537)	(127,226)	(47,324)	(93,608)	(99,302)
Operating data[(1)]					
Net production:					
Natural gas (Mcfd)	158,886	69,408	31,403	35,855	38,644

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands, except per unit data)				
Oil (Bpd)	1,329	330	307	373	427
Natural gas liquids (Bpd)	3,473	974	444	499	101
Total (Mcfed)	187,701	77,232	35,912	41,090	41,814
Average sales price:					
Natural gas (per Mcf)(2):					
Realized price, after hedge(2)	$3.47	$3.29	$4.98	$7.08	$7.54
Realized price, before hedge(2)	$3.25	$2.60	$4.53	$4.60	$4.04
Oil (per Bbl):					
Realized price, after hedge	$91.01	$94.02	$89.70	$77.31	$71.34
Realized price, before hedge	$95.88	$91.32	$89.07	$71.37	$57.41
Natural gas liquids realized price (per Bbl)	$28.71	$31.97	$48.26	$37.78	$36.19
Production costs (per Mcfe):					
Lease operating expenses(3):	$1.09	$0.82	$1.09	$1.27	$1.10
Production taxes	0.18	0.12	0.10	0.04	0.03
Transportation and compression	0.24	0.24	0.43	0.65	0.68
Total	$1.50	$1.19	$1.61	$1.96	$1.80

(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 was $3.21 per Mcf ($2.99 per Mcf before the effects of financial hedging), $2.76 per Mcf ($2.08 per Mcf before the effects of financial hedging), $4.28 per Mcf ($3.83 per Mcf before the effects of financial hedging), $5.78 per Mcf ($3.30 per Mcf before the effects of financial hedging), and $7.13 per Mcf ($3.62 per Mcf before the effects of financial hedging) for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively.

(3) 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 $1.01 per Mcfe ($1.42 per Mcfe for total production costs), $0.58 per Mcfe ($0.94 per Mcfe for total production costs), $0.77 per Mcfe ($1.33 per Mcfe for total production costs), $0.86 per Mcfe ($1.56 per Mcfe for total production costs), and $0.97 per Mcfe ($1.67 per Mcfe for total production costs) for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, 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" or "ATLS" refer to Atlas Energy, L.P. and its consolidated subsidiaries, 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 Delaware 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 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.

At December 31, 2013, Atlas Energy, L.P. ("ATLS"), a publicly traded master-limited partnership (NYSE: ATLS), manages our operations and activities through its ownership of our general partner interest. At December 31, 2013, ATLS 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 36.9% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

We were formed in October 2011 to own and operate substantially all of ATLS' exploration and production assets ("Atlas Energy E&P Operations"), which were transferred to us on March 5, 2012. In February 2012, the board of directors of ATLS' general partner approved the distribution of approximately 5.24 million of our common units which were distributed on March 13, 2012 to ATLS' unitholders using a ratio of 0.1021 of our limited partner units for each of ATLS' common units owned on the record date of February 28, 2012.

On February 17, 2011, ATLS acquired certain assets and liabilities (the "Transferred Business") from Atlas Energy, Inc. ("AEI"), the former owner of ATLS' general partner. These assets principally included the following exploration and production assets which were included within Atlas Energy's E&P Operations:

AEI's investment management business, which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which we fund a portion of our natural gas and oil well drilling;

proved reserves located in the Appalachia Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan, and the Chattanooga Shale of northeastern Tennessee; and

certain producing natural gas and oil properties, upon which we are developers and producers.

FINANCIAL PRESENTATION

Our consolidated balance sheets at December 31, 2013 and 2012, the consolidated statements of operations for the year ended December 31, 2013 and the portion of the year ended December 31, 2012 subsequent to the transfer of assets on March 5, 2012 include our accounts and our wholly-owned subsidiaries. The portion of the consolidated statement of operations for the year ended December 31, 2012 prior to the transfer of assets on March 5, 2012 and the consolidated statement of operations for the year ended December 31, 2011 were derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if we had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all of the various entities comprising Atlas E&P Operations prior to the date of transfer, ATLS' net investment is shown as equity in the consolidated financial statements. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management's best estimates, in order to derive our financial statements for the periods presented prior to the transfer of assets. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the consolidation of the financial statements.

Upon the acquisition of the Transferred Business on February 17, 2011, ATLS' management determined that the 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 assets and liabilities of the Transferred Business 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/equity. 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 financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect of 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/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.

SUBSEQUENT EVENTS

Distribution. On February 24, 2014, we declared our initial monthly distribution of $0.1933 per common unit for the month of January 2014, which is payable on March 17, 2014 to holders of record as of March 7, 2014. In January 2014, our board of directors had approved the modification of our distribution payment practice to a monthly distribution program.

GeoMet Acquisition. On February 13, 2014, we entered into a definitive asset purchase and sale agreement to acquire certain assets from GeoMet, Inc. (“GeoMet”) (OTCQB: GMET) for approximately $107.0 million in cash with an effective date of January 1, 2014, subject to certain purchase price adjustments. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia. The closing of the acquisition is subject to certain closing conditions, including a vote by GeoMet’s stockholders to approve the transaction.

Cash Distribution. On January 29, 2014, we declared a cash distribution of $0.58 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. The $41.8 million distribution, including $2.9 million and $4.4 million to the general partner and preferred limited partners, respectively, was paid on February 14, 2014 to unitholders of record at the close of business on February 10, 2014.

RECENT DEVELOPMENTS

EP Energy Acquisition. On July 31, 2013, we completed the acquisition of assets from EP Energy E&P Company, L.P. (“EP Energy”), a wholly-owned subsidiary of EP Energy, LLC, and EPE Nominee Corp for approximately $709.6 million in cash, net of purchase price adjustments (the “EP Energy Acquisition”). The purchase price was funded through borrowings under our revolving credit facility, the issuance of our 9.25% senior notes due August 15, 2021 (“9.25% Senior Notes), the issuance of 14,950,000 common limited partner units, and the issuance of our newly created Class C convertible preferred units. 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.

Issuance of Preferred Units. In connection with the closing of the EP Energy Acquisition, on July 31, 2013 we issued $86.6 million of our newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of $23.10, which was the face value of the units. The Class C preferred units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (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 initial Class C preferred distribution was paid for the quarter ending September 30, 2013. In connection with the issuance of the Class C preferred units, we also issued to ATLS a warrant to purchase 562,497 of our common units (representing 15% of the Class C preferred units issued (see “Issuance of Units”).

Credit Facility Amendment. On July 31, 2013, in connection with the EP Energy Acquisition, we entered into a Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the “Credit Agreement”). The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks. Our borrowing base is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. On December 6, 2013, we entered into the First Amendment to the Credit Agreement (the “Amendment”). The Amendment redetermined the borrowing base to $735.0 million and set the ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended December 31, 2013, March 31, 2014, and June 30, 2014, 4.25 to 1.0 as of the last day of the quarter ended September 30, 2014 and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter (see "Credit Facility").

9.25% Senior Notes. On July 30, 2013, in connection with the EP Energy Acquisition, we issued $250.0 million of 9.25% Senior Notes, due 2021, in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million, net of underwriting fees and other offering costs of $5.5 million. The net proceeds were used to partially fund the EP Energy Acquisition. The 9.25% Senior Notes were presented combined with a net $1.7 million unamortized discount as of December 31, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date being February 15, 2014 (see "Senior Notes").

Common Unit Offering. In June 2013, in connection with the EP Energy Acquisition, we sold an aggregate of 14,950,000 of our 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 (see "Issuance of Units"). We utilized the net proceeds from the sale to repay the outstanding balance under our revolving credit facility (see "Credit Facility").

Equity Distribution Program. In May 2013, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution agreement, we could sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. Sales of common limited partner units, if any, could be made in negotiated transactions or transactions that were 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 limited partner units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We paid each of the agents a commission, which in each case was not more than 2.0% of the gross sales price of common limited partner units sold through such agent. During the year ended December 31, 2013, we 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. We utilized the net proceeds from the sale to repay borrowings outstanding under our revolving credit facility. We terminated our equity distribution agreement effective December 27, 2013 (see “Issuance of Units”).

7.75% Senior Notes. On January 23, 2013, we issued $275.0 million of 7.75% Senior Notes, due 2021 (“7.75% Senior Notes”), in a private placement transaction at par. During the year ended December 31, 2013, we used the net proceeds of approximately $267.6 million, net of underwriting fees and other offering costs of $7.4 million, to repay all of the indebtedness and accrued interest outstanding under our then-existing term loan credit facility and a portion of the amounts outstanding under our revolving credit facility (see “Credit Facility”). In connection with the retirement of our term loan credit facility and the reduction in our revolving credit facility borrowing base, we accelerated $3.2 million of amortization expense related to deferred financing costs during the year ended December 31, 2013. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15 (see “Senior Notes”).

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 production area and pricing indices for the majority of our production areas are as follows:

· Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline, Transco Leidy Line;

· 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; 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 produced at monthly, fixed index prices and a smaller portion at index daily prices.

We hold firm transportation obligations on Colorado Interstate Gas as a result of the EP Energy Acquisition for the benefit of production from the Raton Basin in the New Mexico/Colorado Area. The total of firm transportation held is approximately 82,500 dth/d at a weighted average rate of $0.2575/MMBtu under contracts expiring in 2014 and 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 charges. 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 mentioned 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, 2013, Enterprise Products Operating LLC, Chevron, and Empire Pipeline Corporation accounted for approximately 19%, 11%, and 10% 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 fund 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. As managing general partner of the Drilling Partnerships, we receive the following 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 well;

- Administration and oversight. For each well drilled by a Drilling Partnership, we receive a fixed fee between $100,000 and $400,000, depending on the type of well drilled. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of $75 for the life of the well. Because we coinvest in the Drilling Partnerships, the net fee that we receive is reduced by our proportionate interest in the well;

- Well services. Each Drilling Partnership pays us a monthly per well operating fee, currently $1,000 to $2,000, for the life of the well. Because we coinvest in the Drilling Partnerships, the net fee that we receive is reduced by our proportionate interest in the wells; and

- Gathering. Each royalty owner, Drilling Partnership and certain other working interest owners pay us a gathering fee, which in general is 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%.

GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by the following key trends. 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 areas in which we operate are experiencing a significant increase in natural gas, oil and NGL production related to new and increased drilling for deeper natural gas formations and the implementation of new exploration and production techniques, including horizontal and multiple fracturing techniques. The increase in the supply of natural gas has put a downward pressure on domestic natural gas prices. 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 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 shale plays throughout the United States. We had certain agreements which restricted our ability to drill additional wells in certain areas of Pennsylvania, New York and West Virginia, including portions of the Marcellus Shale, which expired on February 17, 2014. Through December 31, 2013, we have established production positions in the following operating areas:

the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas, a hydro-carbon producing shale in which we established a position following our acquisitions of assets from Carrizo Oil & Gas, Inc. (“Carrizo”), Titan Operating, LLC (“Titan”) and DTE Energy Company (“DTE”) during 2012;

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, where we established a position following our acquisition of certain assets from EP Energy during 2013 (see “Recent Developments”);

the Appalachia Basin, 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;

the Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area, in which we established a position following our acquisition from Equal in 2012; and

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, both gross and for our interest, and the number of gross wells we turned in line during the years ended December 31, 2013, 2012, and 2011:

	Years Ended December 31,		
	2013	2012	2011
Gross wells drilled:			
Marcellus Shale	—	10	14
Utica	3	5	—
Ohio	—	7	3
Barnett/Marble Falls	75	21	—
Mississippi Lime	25	11	—
Chattanooga	—	—	5
Niobrara	—	51	138
Total	103	105	160
Our share of gross wells drilled[(1)]:			
Marcellus Shale	—	3	2
Utica	1	1	—
Ohio	—	2	1
Barnett/Marble Falls	55	18	—
Mississippi Lime	10	3	—
Chattanooga	—	—	1
Niobrara	—	15	27
Total	66	42	31
Gross wells turned in line:			
Marcellus Shale	9	31	8
Utica	5	—	—
Ohio	—	10	—
Barnett/Marble Falls	82	7	—
Mississippi Lime	21	3	—
Chattanooga	—	5	1
New Albany/Antrim	—	—	13
Niobrara	—	98	77
Total	117	154	99

(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.

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, 2013, 2012, and 2011:

	Years Ended December 31,		
	2013	2012	2011
Production:(1)(2)(3)			
Appalachia:			
Natural gas (MMcf)	13,397	12,403	9,597
Oil (000’s Bbls)	121	102	105
Natural gas liquids (000’s Bbls)	8	4	6
Total (MMcfe)	14,171	13,036	10,262
Coal-bed Methane:			
Natural gas (MMcf)	17,465	—	—
Oil (000’s Bbls)	—	—	—
Natural gas liquids (000’s Bbls)	—	—	—
Total (MMcfe)	17,465	—	—
Barnett/Marble Falls:			
Natural gas (MMcf)	23,744	10,561	—
Oil (000’s Bbls)	295	10	—
Natural gas liquids (000’s Bbls)	1,004	173	—
Total (MMcfe)	31,539	11,661	—
Mississippi Lime/Hunton:			
Natural gas (MMcf)	1,779	510	—
Oil (000’s Bbls)	63	3	—
Natural gas liquids (000’s Bbls)	118	30	—
Total (MMcfe)	2,859	705	—
Other operating areas:			
Natural gas (MMcf)	1,609	1,929	1,866
Oil (000’s Bbls)	7	6	7
Natural gas liquids (000’s Bbls)	138	150	156
Total (MMcfe)	2,477	2,865	2,847
Total production:			
Natural gas (MMcf)	57,993	25,403	11,462
Oil (000’s Bbls)	485	121	112
Natural gas liquids (000’s Bbls)	1,268	357	162
Total (MMcfe)	68,511	28,267	13,108
Production per day:(1)(2)(3)			
Appalachia:			
Natural gas (Mcfd)	36,705	33,889	26,292
Oil (Bpd)	332	278	287
Natural gas liquids (Bpd)	22	10	17
Total (Mcfed)	38,825	35,618	28,116
Coal-bed Methane:			
Natural gas (Mcfd)	47,848	—	—
Oil (Bpd)	—	—	—
Natural gas liquids (Bpd)	—	—	—
Total (Mcfed)	47,848	—	—

Barnett/Marble Falls:			
Natural gas (Mcfd)	65,053	28,855	—
Oil (Bpd)	808	28	—
Natural gas liquids (Bpd)	2,751	473	—
Total (Mcfed)	86,409	31,861	—
Mississippi Lime/Hunton:			
Natural gas (Mcfd)	4,873	1,392	—
Oil (Bpd)	171	8	—
Natural gas liquids (Bpd)	322	81	—
Total (Mcfed)	7,834	1,926	—

	Years Ended December 31,		
	2013	2012	2011
Other operating areas:			
Natural gas (Mcfd)	4,408	5,271	5,111
Oil (Bpd)	18	16	20
Natural gas liquids (Bpd)	378	410	427
Total (Mcfed)	6,786	7,827	7,796
Total production per day:			
Natural gas (Mcfd)	158,886	69,408	31,403
Oil (Bpd)	1,329	330	307
Natural gas liquids (Bpd)	3,473	974	444
Total (Mcfed)	187,701	77,232	35,912

(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; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara shales.

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas, which comprised 83% of our proved reserves on an energy equivalent basis at December 31, 2013. 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, 2013, 2012 and 2011, 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,		
	2013	2012	2011
Production revenues (in thousands):(1)			
Appalachia:			
Natural gas revenue	$36,375	$35,193	$40,431
Oil revenue	10,564	9,678	9,415
Natural gas liquids revenue	223	223	323
Total revenues	$47,162	$45,094	$50,169
Coal-bed Methane:			
Natural gas revenue	$66,055	$—	$—
Oil revenue	—	—	—
Natural gas liquids revenue	—	—	—
Total revenues	$66,055	$—	$—
Barnett/Marble Falls:			
Natural gas revenue	$70,167	$25,545	$—
Oil revenue	26,578	887	—
Natural gas liquids revenue	26,929	4,959	—
Total revenues	$123,674	$31,391	$—
Mississippi Lime/Hunton:			
Natural gas revenue	$7,010	$1,840	$—
Oil revenue	6,452	241	—
Natural gas liquids revenue	5,175	1,140	—
Total revenues	$18,637	$3,221	$—
Other operating areas:			
Natural gas revenue	$6,622	$7,573	$8,665
Oil revenue	566	545	642
Natural gas liquids revenue	4,067	5,077	7,503
Total revenues	$11,255	$13,195	$16,810
Total production revenues:			
Natural gas revenue	$186,229	$70,151	$49,096
Oil revenue	44,160	11,351	10,057
Natural gas liquids revenue	36,394	11,399	7,826
Total revenues	$266,783	$92,901	$66,979
Average sales price:			
Natural gas (per Mcf):(2)			
Total realized price, after hedge(3)	$3.47	$3.29	$4.98
Total realized price, before hedge(3)	$3.25	$2.60	$4.53
Oil (per Bbl):(2)			
Total realized price, after hedge	$91.01	$94.02	$89.70
Total realized price, before hedge	$95.88	$91.32	$89.07

Natural gas liquids (per Bbl) total realized price:[2]	$28.71	$31.97	$48.26
Production costs (per Mcfe):[1] [2]			
Appalachia:			
Lease operating expenses[4]	$1.08	$1.02	$1.20
Production taxes	0.07	0.08	0.11
Transportation and compression	0.47	0.38	0.50
	$1.62	$1.48	$1.80
Coal-bed Methane:			
Lease operating expenses	$0.90	$—	$—
Production taxes	0.23	—	—

	Years Ended December 31, 2013	2012	2011
Transportation and compression	0.34	—	—
	$1.48	$—	$—
Barnett/Marble Falls:			
Lease operating expenses	$1.18	$0.61	$—
Production taxes	0.19	0.18	—
Transportation and compression	0.09	0.12	—
	$1.46	$0.90	$—
Mississippi Lime/Hunton:			
Lease operating expenses	$1.47	$1.38	$—
Production taxes	0.20	0.29	—
Transportation and compression	0.15	—	—
	$1.83	$1.67	$—
Other operating areas:			
Lease operating expenses	$0.76	$0.63	$0.67
Production taxes	0.11	0.06	0.07
Transportation and compression	0.19	0.17	0.19
	$1.05	$0.86	$0.93
Total production costs:			
Lease operating expenses(4)	$1.09	$0.82	$1.09
Production taxes	0.18	0.12	0.10
Transportation and compression	0.24	0.24	0.43
	$1.50	$1.19	$1.61

(1) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming; 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, 2013, 2012 and 2011. Including the effect of this subordination, the average realized gas sales price was $3.21 per Mcf ($2.99 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, 2013, 2012 and 2011, respectively.

(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 for the years ended December 31, 2013, 2012 and 2011. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.69 per Mcfe ($1.23 per Mcfe for total production costs), $0.48 per Mcfe ($0.94 per Mcfe for total production costs) and $0.80 per Mcfe ($1.41 per Mcfe for total production costs) for the years ended December 31, 2013, 2012 and 2011, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $1.01 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, 2013, 2012 and 2011, respectively.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Total natural gas revenues were $186.2 million for the year ended December 31, 2013, an increase of $116.0 million from $70.2 million for year ended December 31, 2012. This increase consisted of a $66.0 million increase attributable to natural gas revenue associated with the newly acquired coal-bed methane assets, a $44.6 million increase attributable to natural gas revenue associated with the Barnett Shale/Marble Falls assets, a $5.2 million increase attributable to the Mississippi Lime/Hunton assets, and a $2.1 million increase primarily attributable to higher production volume on our legacy systems, partially offset by a $1.9 million increase in gas revenues subordinated to the investor partners within our Drilling Partnerships. Total oil revenues were $44.2 million for the year ended December 31, 2013, an increase of $32.8 million from $11.4 million for the comparable prior year period due to a $25.7 million increase attributable to oil revenue associated with the Barnett Shale/Marble Falls assets, a $6.2 million increase attributable to the Mississippi Lime/Hunton assets, and a $0.9 million increase attributable to higher production volume on our legacy systems during the current year period. Total natural gas liquids revenues were $36.4 million for the year ended December 31, 2013, an increase of $25.0 million from $11.4 million for the comparable prior year period. This increase was primarily attributable to a $22.0 million increase of NGL revenue associated with the Barnett Shale/Marble Falls assets and a $4.0 million increase of NGL revenue attributable to the Mississippi Lime/Hunton assets.

Appalachia production costs were $17.4 million for the year ended December 31, 2013, an increase of $5.0 million from $12.4 million for the year ended December 31, 2012. This increase was due to a $3.6 million increase in transportation, labor and other production costs, and a $1.4 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships. Production costs associated with our current year acquisition of coal-bed methane assets were $25.8 million for the year ended December 31. 2013. Production costs associated with our 2012 acquisitions in the Barnett Shale/Marble Falls and Mississippi Lime/Hunton plays were $51.4 million for the year ended December 31, 2013 as compared to $11.7 million for the comparable prior year period. Production costs associated with our other operating areas were $2.6 million for year ended December 31, 2013, compared to $2.5 million for the year ended December 31, 2012. Total production costs per Mcfe increased to $1.50 per Mcfe for the year ended December 31, 2013 from $1.19 per Mcfe for the comparable prior year period primarily as a result of the increase in our oil and natural gas liquids volumes during the current period.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Total natural gas revenues were $70.2 million for the year ended December 31, 2012, an increase of $21.1 million from $49.1 million for the year ended December 31, 2011. This increase consisted of a $25.6 million increase attributable to natural gas revenue associated with the Barnett Shale/Marble Falls assets acquired in 2012, a $1.8 million increase attributable to natural gas revenue associated with the Mississippi Lime/Hunton assets acquired in 2012, and an $11.3 million increase attributable to higher production volume on our legacy systems, partially offset by a $12.3 million decrease attributable to lower realized natural gas prices for production volume on our legacy systems and a $5.3 million increase in gas revenues subordinated to the investor partners within our Drilling Partnerships for the year ended December 31, 2012 compared with the prior year period. Total oil revenues were $11.4 million for the year ended December 31, 2012, an increase of $1.3 million from $10.1 million for the comparable prior year period due primarily to higher production volume during the year ended December 31, 2012. Total natural gas liquids revenues were $11.4 million for the year ended December 31, 2012, an increase of $3.6 million from $7.8 million for the comparable prior year period. This increase is primarily attributable to $5.0 million of NGL revenue associated with the Barnett Shale/Marble Falls assets acquired in 2012, partially offset by lower realized prices.

Appalachia production costs were $12.4 million for the year ended December 31, 2012, a decrease of $2.0 million from $14.4 million for the year ended December 31, 2011. This decrease was principally due to a $2.9 million increase in our credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships, partially offset by a $0.9 million increase in labor and other costs. Production costs associated with our 2012 acquisitions in the Barnett Shale/Marble Falls and Mississippi Lime/Hunton plays were $11.7 million for the year ended December 31, 2012. Production costs associated with our other operating areas were $2.5 million for the year ended December 31, 2012, a decrease of $0.2 million from $2.7 million for the year ended December 31, 2011. Total production costs per Mcfe decreased to $1.19 per Mcfe for the year ended December 31, 2012 from $1.61 per Mcfe for the comparable prior year period primarily as a result of the increase in natural gas volumes during the year ended December 31, 2012.

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. The following table presents the amounts of Drilling Partnership investor capital raised and deployed (in thousands), as well as the number of gross and net development wells we drilled for our Drilling Partnerships during years ended December 31, 2013, 2012 and 2011. There were no exploratory wells drilled during the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
Drilling partnership investor capital:			
Raised	$149,967	$127,071	$141,929
Deployed	$167,883	$131,496	$135,283
Gross partnership wells drilled:			
Marcellus Shale	—	10	14
Utica	3	5	—
Ohio	—	7	3
Barnett/Marble Falls	51	4	—
Mississippi Lime	21	11	—
Chattanooga	—	—	5
Niobrara	—	51	138
Total	75	88	160
Net partnership wells drilled:			
Marcellus Shale	—	10	11
Utica	3	5	—
Ohio	—	7	3
Barnett/Marble Falls	25	2	—
Mississippi Lime	21	9	—
Chattanooga	—	—	5
Niobrara	—	51	138
Total	49	84	157

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 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,		
	2013	2012	2011
Average construction and completion:			
Revenue per well	$3,276	$1,444	$886
Cost per well	2,849	1,253	757
Gross profit per well	$427	$191	$129
Gross profit margin	$21,898	$17,417	$19,653
Partnership net wells associated with revenue recognized(1):			
Marcellus Shale	4	7	15
Utica	5	2	—
Ohio	—	8	2
Barnett/Marble Falls	24	2	—
Mississippi Lime	18	7	—
Chattanooga	—	2	4
New Albany	—	—	3
Niobrara	—	63	129
Total	51	91	153

(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, 2013 Compared with the Year Ended December 31, 2012. Well construction and completion segment margin was $21.9 million for the year ended December 31, 2013, an increase of $4.5 million from $17.4 million for the year ended December 31, 2012. This increase consisted of a $12.1 million increase associated with higher gross profit margin per well, partially offset by a $7.6 million decrease related to a lower number of wells recognized for revenue within our Drilling Partnerships. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Utica Shale, Mississippi Lime play, and Marble Falls play wells within the Drilling Partnerships during the year ended December 31, 2013, compared with higher capital deployed for lower cost Niobrara Shale wells during the prior year period. Since 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, 2012 Compared with the Year Ended December 31, 2011. Well construction and completion segment margin was $17.4 million for the year ended December 31, 2012, a decrease of $2.3 million from

$19.7 million for the year ended December 31, 2011. This decrease consisted of a $7.9 million decrease related to a decreased number of wells recognized for revenue within our Drilling Partnerships, partially offset by a $5.6 million increase associated with higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Marcellus Shale and Utica Shale wells within the Drilling Partnerships during 2012.

At December 31, 2013, our consolidated balance sheet includes $49.4 million of “liabilities associated with 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 have not been recognized as well construction and completion revenue on our consolidated statement of operations. We expect to recognize this amount as revenue during 2014.

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 and Niobrara Shale, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Administration and oversight fee revenues were $12.3 million for the year ended December 31, 2013, an increase of $0.5 million from $11.8 million for the year ended December 31, 2012. This increase was due primarily to current year period increases in the number of wells drilled within the Mississippi Lime Shale and Marble Falls play, partially offset by a decrease in the number of Marcellus Shale wells drilled during the current year period.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Administration and oversight fee revenues were $11.8 million for the year ended December 31, 2012, an increase of $4.1 million from $7.7 million for the year ended December 31, 2011. This increase was primarily due to an increase in the number of horizontal wells drilled in both the Mississippi Lime and Utica Shale during the year ended December 31, 2012 and an increase in the number of Marcellus Shale wells drilled during the year ended December 31, 2012 in comparison to the prior year period.

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, 2013 Compared with the Year Ended December 31, 2012. Well services revenues were $19.5 million for the year ended December 31, 2013, a decrease of $0.5 million from $20.0 million for the year ended December 31, 2012. Well services expenses were $9.5 million for the year ended December 31, 2013, an increase of $0.2 million from $9.3 million for the year ended December 31, 2012. The decrease in well services revenue is primarily related to lower equipment rental revenue during the year ended December 31, 2013 as compared with the comparable prior year period. The increase in well services expense is primarily related to higher well labor costs.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Well services revenues were $20.0 million for the year ended December 31, 2012, an increase of $0.2 million from $19.8 million for the year ended December 31, 2011. Well services expenses were $9.3 million for the year ended December 31, 2012, an increase of $0.6 million from $8.7 million for the year ended December 31, 2011. The increase in well services revenue is primarily related to higher equipment rental revenue during the year ended December 31, 2012 as compared with the comparable prior year period. The increase in well services expenses is primarily related to higher well 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, 2013 Compared with the Year Ended December 31, 2012. Our net gathering and processing expense for the year ended December 31, 2013 was $2.3 million, a decrease of $0.9 million compared with net expense of $3.2 million for the year ended December 31, 2012. This favorable decrease was principally due to an increase in gathering fees associated with our new Marcellus wells in Northeastern Pennsylvania.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Our net gathering and processing expense for the year ended December 31, 2012 was $3.2 million, comparable with $3.1 million for the year ended December 31, 2011. This unfavorable increase was principally due to an increase in natural gas volume in the Appalachian Basin between the periods, partially offset by a decrease in our average realized natural gas price.

Other, net

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Other, net for the year ended December 31, 2013 was an expense of $14.5 million, compared with expense of $4.9 million for the year ended December 31, 2012. The $14.5 million of other expense for the year ended December 31, 2013 was primarily related to premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from EP Energy in the current year period (see “Recent Developments”). The $4.9 million of other expense for the year ended December 31, 2012 was primarily related to the premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from Carrizo during the prior year period.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Other, net for the year ended December 31, 2012 was an expense of $4.9 million compared with expense of approximately $30,000 for the year ended December 31, 2011. The $4.9 million unfavorable movement compared with the prior year period was primarily due to the premium amortization associated with derivative contracts for production volumes related to wells acquired from Carrizo.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Total general and administrative expenses increased to $78.1 million for the year ended December 31, 2013 compared with $69.1 million for the year ended December 31, 2012. This increase was primarily due to a $7.7 million increase in non-recurring transaction costs related to the acquisitions of assets in the current and prior year period and $1.8 million increase in non-cash compensation expense, partially offset by a $0.5 million decrease in other corporate activities.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Total general and administrative expenses increased to $69.1 million for the year ended December 31, 2012 compared with $27.5 million for the year ended December 31, 2011. This increase was primarily due to a $22.1 million increase in non-recurring transaction costs related to our 2012 acquisitions of assets, an $18.6 million unfavorable movement related to a decrease in net reimbursements we received under our transition services agreement with Chevron which expired during the first quarter of 2012 and a $10.8 million increase in non-cash compensation expense, partially offset by a $9.9 million decrease in salaries and wages and other corporate activities.

Chevron Transaction Expense

During the year ended December 31, 2012, we recognized a $7.7 million charge regarding our reconciliation process with Chevron related to certain amounts included within the contractual cash transaction adjustment, which was settled in October 2012 (see “Item 8: Financial Statements and Supplementary Data – Note 3”).

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization increased to $136.8 million for the year ended December 31, 2013 compared with $52.6 million for the comparable prior year period, which was due to a $82.7 million increase in our depletion expense resulting from the acquisitions we consummated during 2012 and 2013.

Total depreciation, depletion and amortization increased to $52.6 million for the year ended December 31, 2012 compared with $30.9 million for the comparable prior year period primarily due to a $19.6 million increase in our depletion expense.

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 per Mcfe data):

	Years Ended December 31,		
	2013	2012	2011
Depreciation, depletion and amortization:			
Depletion expense	$129,729	$47,000	$27,430
Depreciation and amortization expense	7,034	5,582	3,439
	$136,763	$52,582	$30,869
Depletion expense:			
Total	$129,729	$47,000	$27,430
Depletion expense as a percentage of gas and oil production revenue	49 %	51 %	41 %
Depletion per Mcfe	$1.89	$1.66	$2.09

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, 2013, depletion expense was $129.7 million, an increase of $82.7 million compared with $47.0 million for the year ended December 31, 2012. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 49% for the year ended December 31, 2013, compared with 51% for the year ended December 31, 2012, which was primarily due to an increase in our oil and natural gas liquids revenues as a result of our acquisitions in 2012, partially offset by a decrease in realized natural gas prices between the periods. Depletion expense per Mcfe increased to $1.89 for the year ended December 31, 2013, compared to $1.66 for the prior year comparable period primarily due to the increase in oil and natural gas liquids production between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

For the year ended December 31, 2012, depletion expense was $47.0 million, an increase of $19.6 million in comparison with $27.4 million for the year ended December 31, 2011. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 51% for the year ended December 31, 2012, compared with 41% for the year ended December 31, 2011, which was primarily due to a decrease in realized natural gas prices between the periods. Depletion expense per Mcfe was $1.66 for the year ended December 31, 2012, a decrease of $0.43 per Mcfe from $2.09 for the year ended December 31, 2011, primarily related to lower depletion expense per Mcfe for the assets acquired from Carrizo and Titan Acquisitions and the addition of reserves for new Marcellus Shale wells, which began production during the year ended December 31, 2012. Depletion expense increased between periods principally due to an overall increase in production volume.

Asset Impairment

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Asset impairment for the year ended December 31, 2013 was $38.0 million as compared with $9.5 million for the comparable prior year period. The $38.0 million of asset impairment during the year ended December 31, 2013 was 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. During the year ended December 31, 2012, we recognized $9.5 million of asset impairment related to gas and oil properties within property, plant and equipment on our consolidated balance sheet for our shallow natural gas wells in the Antrim and Niobrara 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, 2013 and 2012 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 natural gas prices in comparison to their carrying values at December 31, 2013 and 2012.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Asset impairment for the year ended December 31, 2012 was $9.5 million as compared with $7.0 million for the comparable prior year period. During the year ended December 31, 2012, we recognized $9.5 million of asset impairment related to gas and oil properties within property, plant and equipment on our consolidated balance sheet for our shallow natural gas wells in the Antrim and Niobrara shales. During the year ended December 31, 2011, we recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment on our consolidated balance sheet for our shallow natural gas wells in the Niobrara Shale. These impairments related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair value at December 31, 2012 and 2011. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices in comparison to their carrying values at December 31, 2012 and 2011.

Interest Expense

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Interest expense for the year ended December 31, 2013 was $34.3 million as compared with $4.2 million for the comparable prior year period. The $30.1 million increase consisted of a $20.9 million increase associated with the issuance of our 7.75% Senior Notes, a $10.1 million increase associated with the issuance of our 9.25% Senior Notes, a $7.8 million increase associated with amortization of deferred financing costs and a $3.1 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility and then-existing term loan credit facility, partially offset by interest that was capitalized on our ongoing capital projects. The increase in amortization associated with deferred financing costs includes $5.3 million associated with our revolving credit facility, $3.2 million of accelerated amortization related to the retirement of our then-existing term loan credit facility and the reduction in our revolving credit facility borrowing base subsequent to our issuance of the 7.75% Senior Notes and $1.2 million associated with our issuance of senior notes, partially offset by a $1.9 million decrease in amortization expense related to the extension of our credit facility maturity date from 2016 to 2018.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Interest expense for the year ended December 31, 2012 was $4.2 million, which was associated with outstanding borrowings under our revolving credit facility and term loan credit facility and amortization of deferred financing costs associated with the credit facility (see “Credit Facility”). There was no interest expense for the year ended December 31, 2011.

Gain (Loss) on Asset Sales and Disposal

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. During the years ended December 31, 2013 and 2012, we recognized losses on asset sales and disposals of $1.0 million and $7.0 million, respectively. 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. During the year ended December 31, 2012, we recognized a $7.0 million loss on asset sales and disposal related to management’s decision to terminate a farm-out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm-out agreement contained certain well drilling milestones, which needed to be met in order for us to maintain ownership of the South Knox processing plant. During 2012, management decided not to continue progressing towards these milestones due to the current natural gas price environment. As a result, we forfeited our interest in the processing plant and recorded a loss related to the net book value of the assets during the year ended December 31, 2012.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. During the years ended December 31, 2012 and 2011, we recognized a $7.0 million loss on asset sales and disposal and a $0.1 million gain on asset sales and disposal, respectively. The $7.0 million loss on asset sales and disposal for the year ended December 31, 2012 pertained to management’s decision to terminate a farm-out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm-out agreement contained certain well drilling milestones which needed to be met in order for us to maintain ownership of the South Knox processing plant. During 2012, management decided not to continue progressing towards these milestones due to the current natural gas price environment. As a result, we forfeited our interest in the processing plant and recorded a loss related to the net book value of the assets during the year ended December 31, 2012.

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 credit facility (see "Credit Facility"). 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 common units or asset sales.

We rely on cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve month period. However, we are subject to business, operational and other risks that could adversely affect our cash flow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units, the sale of assets and other transactions.

Cash Flows – Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

Net cash provided by operating activities of $122.9 million for the year ended December 31, 2013 represented a favorable movement of $106.4 million from net cash provided by operating activities of $16.5 million for the comparable prior year period. The $106.4 million favorable movement in net cash provided by operating activities resulted from an $88.1 million favorable movement in net income excluding non-cash items and an $18.3 million favorable movement in working capital. The $88.1 million favorable movement in net income excluding non-cash items included an $84.2 million increase in depreciation, depletion and amortization expense, a $28.5 million favorable movement in asset impairment, an $11.1 million favorable movement in non-cash gain on derivative value, a $7.7 million increase in amortization of deferred financing costs relating to our revolving and then-existing term loan credit facilities, our 9.25% Senior Notes and our 7.75% Senior Notes, and a $1.9 million increase in non-cash stock compensation, partially offset by a $39.3 million unfavorable movement in net loss and a $6.0 million unfavorable movement in (gain)/loss on asset sales and disposal. The $84.2 million increase in depreciation, depletion and amortization expense is primarily related to the acquisitions of oil and gas properties made in 2012 and 2013. The $11.1 million favorable movement in non-cash (gain)/loss on derivative value is primarily related to the movement in natural gas prices in comparison to our hedge prices for derivative contracts expiring during the respective periods. The $18.3 million favorable movement in working capital was principally due to a $43.2 million favorable movement in accounts receivable, prepaid expenses and other, partially offset by a $24.9 million unfavorable movement in accounts payable and accrued liabilities. The favorable movement in accounts receivable, prepaid expenses and other was primarily due to a favorable movement in subscriptions receivable due to the timing of funds raised. The unfavorable movement in accounts payable and accrued liabilities was primarily due to an unfavorable movement in accrued well drilling and completion costs between respective periods.

Net cash used in investing activities of $984.6 million for the year ended December 31, 2013 represented an unfavorable movement of $340.3 million from net cash used in investing activities of $644.3 million for the comparable prior year period. This unfavorable movement was primarily due to an increase in net cash paid for acquisitions during the year ended December 31, 2013 as compared to the year ended December 31, 2012 and an increase in capital expenditures. See further discussion of capital expenditures under “Capital Requirements”.

Net cash provided by financing activities of $840.3 million for the year ended December 31, 2013 represented a favorable movement of $244.0 million from net cash provided by financing activities of $596.3 million for the comparable prior year period. This movement was principally due to an increase of $510.4 million in net proceeds from the issuance of our 9.25% Senior Notes and 7.75% Senior Notes (see “Senior Notes”), an increase of $274.9 million in borrowings under our revolving credit facility, an increase of $86.6 million from the issuance of our Class C preferred units and warrants and an increase of $29.9 million in net proceeds from the issuance of our common limited partner units, partially offset by an increase of $558.8 million in repayments under our revolving and then-existing term loan credit facilities, a $91.1 million increase in cash distributions paid to unitholders, a $5.6 million unfavorable movement in the net investment from owners and a $2.3 million unfavorable movement in deferred financing costs, distribution equivalent rights and other. The gross amount of borrowings and repayments under our revolving credit facility 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 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.

Cash Flows – Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011

Net cash provided by operating activities of $16.5 million for the year ended December 31, 2012 represented an unfavorable movement of $54.9 million from net cash provided by operating activities of $71.4 million for the comparable prior year period. The $54.9 million unfavorable movement in net cash provided by operating activities resulted from an $85.2 million unfavorable movement in net income excluding non-cash items, partially offset by a $30.3 million favorable movement in working capital. The $85.2 million unfavorable movement in net income excluding non-cash items included a $71.8 million decrease in net income and a $57.3 million unfavorable movement in non-cash (gain) loss on derivative value, partially offset by a $21.7 million increase in depreciation, depletion and amortization expense, a $10.8 million increase in non-cash stock compensation, a $7.1 million increase in gain (loss) on asset disposal, a favorable movement of $2.5 million in asset impairment and a $1.8 million increase in amortization of deferred financing costs relating to our credit facility assumed by us from ATLS and further amended in 2012. The $57.3 million unfavorable movement in non-cash (gain) loss on derivative value is primarily related to the distribution of $36.2 million non-cash loss on derivative value during the year ended December 31, 2011 resulting from the monetization of hedges prior to the acquisition of the Transferred Business from AEI and a $21.1 million non-cash gain on derivative value for the year ended December 31, 2012 related to a decline in natural gas prices during the period. The $30.3 million favorable movement in working capital was principally due to a $33.9 million favorable movement in accounts payable and other current liabilities partially offset by a $3.6 million unfavorable movement in accounts receivable and other current assets. The favorable movement in accounts payable and other current liabilities was primarily due to a favorable movement in accounts payable and liabilities associated with well drilling and completion costs, partially offset by an unfavorable movement in accrued liabilities and liabilities associated with drilling contracts. The unfavorable movement in accounts receivable and other current assets was primarily due to an increase in accounts receivable partially offset by a favorable movement in subscriptions receivable. In 2011, the increase in subscriptions receivable for funds raised for our new drilling program in the fourth quarter of 2011 was greater than the increase in subscriptions receivable in 2012 for funds raised for our new drilling program in 2012.

Net cash used in investing activities of $644.3 million for the year ended December 31, 2012 represented an unfavorable movement of $596.8 million from net cash used in investing activities of $47.5 million for the comparable prior year period. This unfavorable movement was principally due to a $516.7 million unfavorable movement in net cash paid for the Carrizo, Titan, Equal and DTE asset acquisitions and a $79.9 million unfavorable movement in capital expenditures. See further discussion of capital expenditures under “Capital Requirements”.

Net cash provided by financing activities of $596.3 million for the year ended December 31, 2012 represented a favorable movement of $565.5 million from net cash provided by financing activities of $30.8 million for the comparable prior year period. This movement was principally due to an increase of $667.1 million in borrowings under our revolving and term loan credit facilities and a $290.1 million increase in net proceeds from issuance of common limited partner units, partially offset by an increase of $315.7 million in repayments under our revolving and term loan credit facilities, a $33.9 million increase in cash distributions paid to unitholders, a net decrease of $25.1 million in the net investment from owners prior to March 5, 2012 and a $17.0 million unfavorable movement in deferred financing costs, distribution equivalent rights and other resulting from the cash paid for revolving and term loan credit facility financing costs. The net decrease in the net investment from owners was due to an increase of $5.6 million for the investment received from ATLS in 2012, partially offset by a decrease of $30.8 million in the net investment received in from AEI in 2011. The gross amount of borrowings and repayments under our revolving credit facility 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 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.

Our July 2012 acquisition of Titan in exchange for 3.8 million common units and 3.8 million newly created convertible Class B preferred units (which had an estimated collective value of $193.2 million, based upon the closing price of our publicly traded units as of the acquisition close date) represented a non-cash transaction during the year ended December 31, 2012.

Capital Requirements

Our capital requirements 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 and Marble Falls 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,		
	2013	2012	2011
Maintenance capital expenditures	$31,500	$10,200	$9,833
Expansion capital expenditures	232,037	117,026	37,491

Total	$263,537	$127,226	$47,324

During the year ended December 31, 2013, our $263.5 million of total capital expenditures consisted primarily of $110.8 million for wells drilled exclusively for our own account compared with $27.3 million for the comparable prior year period, $92.3 million of investments in our Drilling Partnerships compared with $54.4 million for the prior year comparable period, $20.9 million of leasehold acquisition costs compared with $35.6 million for the prior year comparable period and $39.5 million of corporate and other costs compared with $9.9 million for the prior year comparable period, which primarily related to an increase in capitalized interest expense.

During the year ended December 31, 2012, our $127.2 million of total capital expenditures consisted primarily of $54.4 million of investments in our Drilling Partnerships compared with $28.2 million for the prior year comparable period, $27.3 for wells drilled exclusively for our own account compared with $0.6 million for the prior year comparable period, $35.6 million of leasehold acquisition costs compared with $9.5 million for the prior year comparable period, and $9.9 million of corporate and other compared with $9.0 million for the prior year comparable period. The increase in investments in our Drilling Partnerships was principally the result of the cancellation of the Fall 2010 drilling program and the resulting reduction of partnership capital deployed during 2011. Capital expenditures related to our investments in our Drilling Partnerships are generally incurred in the period subsequent to the period in which the funds were raised. The net increase in leasehold acquisition costs principally related to additional Marcellus Shale and Utica Shale acreage acquired through subsequent leasehold acquisitions in the region during the year ended December 31, 2012.

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, 2013, we are committed to expend approximately $11.8 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, 2013, our off-balance sheet arrangements were limited to our letters of credit outstanding of $3.6 million and commitments to spend $11.8 million related to our drilling and completion and capital expenditures, excluding acquisitions.

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, our Board of Directors approved a modification to our distribution payment practice to a monthly distribution program. This new policy took effect for the month of January 2014, for which its monthly cash distribution will be paid in March 2014. Monthly cash distributions will be paid approximately 45 days following the end of each respective monthly period.

Available cash will generally be distributed: first, 98% to our Class B preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class B preferred unit the greater of $0.40 and the distribution payable to common unitholders; 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 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, 2013 (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	$944,000	$—	$—	$419,000	$525,000
Interest on total debt	$372,246	$54,445	$108,890	$104,695	$104,216
Operating leases	$18,790	$3,903	$5,685	$4,062	$5,140
Total contractual cash obligations	$1,335,036	$58,348	$114,575	$527,757	$634,356

	Total	Amount of Commitment Expiration Per Period Less than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Other commercial commitments:					
Standby letters of credit	$3,562	$3,562	$—	$—	$ —
Other commercial commitments[1]	$27,840	$13,104	$12,985	$1,388	$ 363
Total commercial commitments	$31,402	$16,666	$12,985	$1,388	$ 363

(1) Our other commercial commitments include our share of drilling and completion commitments and our throughput contracts, including firm transportation obligations for natural gas as a result of the EP Energy Acquisition. 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 there will be continuing changes. Trends in environmental regulation include increased reporting obligations and placing more restrictions and limitations on activities, such as emissions of greenhouse gases and other pollutants; generation and disposal of wastes, including wastes that may have naturally occurring radioactivity; 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.

CHANGES IN PRICES AND INFLATION

Our revenues, the value of our assets, our ability to obtain bank loans or additional capital on attractive terms, and our ability to finance our drilling activities through Drilling Partnerships, have been and will continue to be affected by changes in natural gas and oil market prices. Natural gas and oil prices are subject to significant fluctuations that are beyond our ability to control or predict.

Inflation affects the operating expenses of our operations. Inflationary trends may occur if commodity prices were to increase, since such an increase may cause the demand for energy equipment and services to increase, thereby increasing the costs of acquiring or obtaining such equipment and services. Increases in those expenses are not necessarily offset by increases in revenues and fees that our operations are able to charge. While we anticipate that inflation will affect our future operating costs, we cannot predict the timing or amounts of any such effects.

CREDIT FACILITY

On July 31, 2013, in connection with the EP Energy Acquisition (see “Recent Developments”), we entered into the Credit Agreement, which amended and restated our existing revolving credit facility. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks scheduled to mature in July 2018. Our borrowing base is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. On December 6, 2013, we entered into the Amendment. The Amendment to the Credit Agreement redetermined the borrowing base to $735.0 million and amended the ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable). The Credit Agreement has a maximum facility amount of $1.5 billion. At December 31, 2013, $419.0 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 $3.6 million was outstanding at December 31, 2013. 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 of our non-guarantor subsidiaries are minor. Borrowings under the credit facility bear interest, at our election, at either an adjusted LIBOR rate plus an applicable margin between 1.75% and 2.75% per annum 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 0.75% and 1.75% per annum. We are also required to pay a fee on the unused portion of the borrowing base at a rate of 0.5% per annum if 50% or more of the borrowing base is utilized and 0.375% per annum if less than 50% of the borrowing base is utilized, which is included within interest expense on our consolidated statements of operations.

The Credit Agreement contains customary covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. We were in compliance with these covenants as of December 31, 2013. The Credit Agreement also requires us to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended December 31, 2013, March 31, 2014, and June 30, 2014, 4.25 to 1.0 as of the last day of the quarter ended September 30, 2014, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter 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.

SENIOR NOTES

On July 30, 2013 we issued $250.0 million of 9.25% Senior Note, due 2021,s in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million. The net proceeds were used to partially fund the EP Energy Acquisition (see “Recent Developments”). The 9.25% Senior Notes were presented combined with a net $1.7 million unamortized discount as of December 31, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date on February 15, 2014. 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%. In addition, at any time prior to August 15, 2016, we may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if we experience specific kinds of changes of control, we must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the 9.25% Senior Notes, 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 not later than 365 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If we fail to comply with our obligations to register the 9.25% Senior Notes within the specified time periods, the 9.25% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective as applicable.

On January 23, 2013, we issued $275.0 million of our 7.75% Senior Notes, due 2021, in a private placement transaction at par. The net proceeds of approximately $267.6 million were used to repay all of the indebtedness and accrued interest outstanding under our then-existing term loan credit facility and a portion of the amounts outstanding under our revolving credit facility. In connection with the retirement of our then-existing term loan credit facility and the reduction in our revolving credit facility borrowing base, we accelerated $3.2 million of amortization expense related to deferred financing costs during the year ended December 31, 2013. 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 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 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing 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. On July 1, 2013, we filed a registration statement relating to the exchange offer for the 7.75% Senior Notes and the exchange offer was completed on January 2, 2014.

The 9.25% Senior Notes and 7.75% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 9.25% Senior Notes and 7.75% Senior Notes are full and unconditional and joint and several, and any of our subsidiaries, 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 9.25% Senior Notes and 7.75% Senior Notes contain covenants, including limitations of 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.

SECURED HEDGE FACILITY

At December 31, 2013, 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 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 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

Equity Offerings

In July 2013, in connection with the EP Energy Acquisition (see "Recent Developments"), we issued $86.6 million of our newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of $23.10, which was the face value of the units. 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 initial Class C preferred distribution was paid for the quarter ending September 30, 2013. 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 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.

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.

In June 2013, in connection with the EP Energy Acquisition (see "Recent Developments"), we sold an aggregate of 14,950,000 of our 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. We utilized the net proceeds from the sale to repay the outstanding balance under our revolving credit facility (see "Credit Facility").

In May 2013, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution agreement, we could sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. Sales of common limited partner units, if any, could be made in negotiated transactions or transactions that were 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 limited partner units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We paid each of the agents a commission, which in each case was not more than 2.0% of the gross sales price of common limited partner units sold through such agent.

During the year ended December 31, 2013, we 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. We utilized the net proceeds from the sale to repay borrowings outstanding under our revolving credit facility. We terminated our equity distribution agreement effective December 27, 2013.

In November and December 2012, in connection with entering into a purchase agreement to acquire certain producing wells and net acreage from DTE, we sold an aggregate of 7,898,210 of our common limited partner units in a public offering at a price of $23.01 per unit, yielding net proceeds of approximately $174.5 million. We utilized the net proceeds from the sale to repay a portion of the outstanding balance under our revolving credit facility and $2.2 million under our then-existing term loan credit facility.

In July 2012, we completed the acquisition of certain proved reserves and associated assets in the Barnett Shale from Titan in exchange for 3.8 million of our common units and 3.8 million newly-created convertible Class B preferred units (which have an estimated collective value of $193.2 million, based upon the closing price of our publicly traded common units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments. The Class B preferred units are voluntarily convertible to common units on a one-for-one basis within three years of the acquisition closing date at a strike price of $26.03 plus all unpaid preferred distributions per unit, and will be mandatorily converted to common units on the third anniversary of the issuance. While outstanding, the preferred units will receive regular quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

On September 19, 2012, we filed a registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement, and the registration statement was declared effective by the SEC on October 2, 2012.

In April 2012, we completed the acquisition of certain oil and gas assets from Carrizo. To partially fund the acquisition, we sold 6.0 million of our common units in a private placement at a negotiated purchase price per unit of $20.00, for net proceeds of $119.5 million, of which $5.0 million was purchased by certain of our executives. The common units issued by us were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that we would (a) file a registration statement with the SEC by October 30, 2012 and (b) cause the registration statement to be declared effective by the SEC by December 31, 2012. On July 11, 2012, we filed a registration statement with the SEC for the common units subject to the registration rights agreement in satisfaction of the registration requirements of the registration rights agreement, and on August 28, 2012, the registration statement was declared effective by the SEC.

Common Unit Distribution

In February 2012, the board of directors of ATLS' general partner approved the distribution of approximately 5.24 million of our common units which were distributed on March 13, 2012 to ATLS' unitholders using a ratio of 0.1021 limited partner units for each of ATLS' common units owned on the record date of February 28, 2012.

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 drilling have driven an increase in the supply of natural gas and put a downward pressure on domestic prices. Further declines in natural gas prices may result in additional impairment charges in future periods.

During the year ended December 31, 2013, we recognized $38.0 million of asset impairments primarily related to our shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany shales. During the year ended December 31, 2012, we recognized $9.5 million of asset impairments related to gas and oil properties within property, plant and equipment, net on our consolidated balance sheet for shallow natural gas wells in the Antrim and Niobrara shales. During the year ended December 31, 2011, we recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment, net on our consolidated balance sheet for shallow natural gas wells in the Niobrara 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, 2013, 2012 and 2011 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 natural gas 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, 2013, 2012 and 2011.

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 year ended December 31, 2013, we completed the EP Energy Acquisition. During the year ended December 31, 2012, we completed the acquisitions of certain oil and gas assets from Carrizo and reserves and associated assets from Titan, Equal and DTE. 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 8: Financial Statements and Supplementary Data - Note 7”). 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, 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 Wright and Company, Inc., an independent third-party reserve engineer, to prepare a report 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 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 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, 2013. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties related to our commodity derivative contracts are banking institutions or their affiliates, who also participate in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we currently believe them to be financially viable. We are not aware of any inability on the part of our counterparties to perform under their contracts and believe our exposure to non-performance is remote.

Interest Rate Risk. At December 31, 2013, $419.0 million was outstanding under our revolving credit 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, 2014 by $4.2 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, 2014 of approximately $13.5 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. These contracts have qualified and been designated as cash flow hedges and been recorded at their fair values.

At December 31, 2013, 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)
2014	60,153,000	$ 4.152
2015	51,474,500	$ 4.236
2016	45,746,300	$ 4.311
2017	24,840,000	$ 4.532
2018	3,960,000	$ 4.716

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)
2014	Puts purchased	3,840,000	$ 4.221
2014	Calls sold	3,840,000	$ 5.120
2015	Puts purchased	3,480,000	$ 4.234
2015	Calls sold	3,480,000	$ 5.129

Natural Gas Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)
2014	Puts purchased	1,800,000	$ 3.800
2015	Puts purchased	1,440,000	$ 4.000

2016	Puts purchased	1,440,000	$ 4.150

Natural Gas Liquids Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)
2014	105,000	$ 91.571
2015	96,000	$ 88.550
2016	84,000	$ 85.651
2017	60,000	$ 83.780

Natural Gas Liquids Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2014	2,520,000	$ 0.303

Natural Gas Liquids Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2014	12,348,000	$ 0.996
2015	8,064,000	$ 1.016

Natural Gas Liquids Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2014	1,512,000	$ 1.308
2015	1,512,000	$ 1.248

Natural Gas Liquids Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2014	1,512,000	$ 1.323
2015	1,512,000	$ 1.263

Crude Oil Fixed Price Swaps

Production Period Ending	Volumes	Average Fixed Price

December 31,		
	(Bbl)(1)	(per Bbl)(1)
2014	552,000	$ 92.668
2015	567,000	$ 88.144
2016	225,000	$ 85.523
2017	132,000	$ 83.305

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)(1)	Average Floor and Cap (per Bbl)(1)
2014	Puts purchased	41,160	$ 84.169
2014	Calls sold	41,160	$ 113.308
2015	Puts purchased	29,250	$ 83.846
2015	Calls sold	29,250	$ 110.654

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

ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), changes in partners’ capital, and cash flows for each of the three years in the period ended December 31, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in the 1992 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2014 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

February 28, 2014

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	$1,828	$23,188
Accounts receivable	58,822	38,718
Current portion of derivative asset	1,891	12,274
Subscriptions receivable	47,692	55,357
Prepaid expenses and other	10,097	9,063
Total current assets	120,330	138,600
Property, plant and equipment, net	2,120,818	1,302,228
Intangible assets, net	963	1,320
Goodwill, net	31,784	31,784
Long-term derivative asset	27,084	8,898
Long-term derivative asset receivable from Drilling Partnerships	863	—
Other assets, net	41,958	16,122
	$2,343,800	$1,498,952
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$69,346	$59,549
Advances from affiliates	26,742	5,853
Liabilities associated with drilling contracts	49,377	67,293
Current portion of derivative liability	6,353	—
Current portion of derivative payable to Drilling Partnerships	2,676	11,293
Accrued well drilling and completion costs	40,481	47,637
Accrued interest	20,622	1,153
Accrued liabilities	28,118	24,235
Total current liabilities	243,715	217,013
Long-term debt	942,334	351,425
Long-term derivative liability	67	888
Long-term derivative payable to Drilling Partnerships	—	2,429
Asset retirement obligations and other	90,393	65,191
Commitments and contingencies		

Partners' Capital:		
General partner's interest	4,482	7,029
Preferred limited partners' interests	183,477	96,155
Class C common limited partner warrants	1,176	—
Common limited partners' interests	852,457	737,253
Accumulated other comprehensive income	25,699	21,569
Total partners' capital	1,067,291	862,006
	$2,343,800	$1,498,952

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,		
	2013	2012	2011
Revenues:			
Gas and oil production	$266,783	$92,901	$66,979
Well construction and completion	167,883	131,496	135,283
Gathering and processing	15,676	16,267	17,746
Administration and oversight	12,277	11,810	7,741
Well services	19,492	20,041	19,803
Other, net	(14,456)	(4,886)	(30)
Total revenues	467,655	267,629	247,522
Costs and expenses:			
Gas and oil production	97,237	26,624	17,100
Well construction and completion	145,985	114,079	115,630
Gathering and processing	18,012	19,491	20,842
Well services	9,515	9,280	8,738
General and administrative	78,063	69,123	27,536
Chevron transaction expense	—	7,670	—
Depreciation, depletion and amortization	136,763	52,582	30,869
Asset impairment	38,014	9,507	6,995
Total costs and expenses	523,589	308,356	227,710
Operating income (loss)	(55,934)	(40,727)	19,812
Interest expense	(34,324)	(4,195)	—
Gain (loss) on asset sales and disposal	(987)	(6,980)	87
Net income (loss)	(91,245)	(51,902)	19,899
Preferred limited partner dividends	(11,992)	(3,063)	—
Net income (loss) attributable to owner's interest, common limited partners and the general partner	$(103,237)	$(54,965)	$19,899
Allocation of net income (loss):			
Portion applicable to owner's interest (period prior to the transfer of assets on March 5, 2012)	$—	$250	$19,899
Portion applicable to common limited partners and the general partner's interests (period subsequent to the transfer of assets on March 5, 2012)	(103,237)	(55,215)	—
Net income (loss) attributable to owner's interest, common limited partners and the general partner	$(103,237)	$(54,965)	$19,899

Allocation of net income (loss) attributable to common limited partners and the general partner:			
Common limited partners' interest	$(106,581)	$(54,260)	$—
General partner's interest	3,344	(955)	—
Net loss attributable to common limited partners and the general partner	$(103,237)	$(55,215)	$—
Net loss attributable to common limited partners per unit:			
Basic and Diluted	$(2.03)	$(1.59)	$—
Weighted average common limited partner units outstanding:			
Basic and Diluted	52,528	34,039	—

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended December 31,		
	2013	2012	2011
Net income (loss)	$(91,245)	$(51,902)	$19,899
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as cash flow hedges	13,852	10,921	35,156
Less: reclassification adjustment for realized gains of cash flow hedges in net income (loss)	(9,722)	(19,281)	(10,542)
Total other comprehensive income (loss)	4,130	(8,360)	24,614
Comprehensive income (loss) attributable to owner's interest, common and preferred limited partners and the general partner	$(87,115)	$(60,262)	$44,513

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

(in thousands, except unit data)

General Partners' Interest		Preferred Limited Partners' Interest				Common Limited Partners' Interests		Class C Common Limited Partner Warrants			Accum Other
Class A		Class B		Class C							Compr
Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Amount	Equity	Income
—	$—	—	$—	—	$—	—	$—	—	$—	$376,567	$5,315
—	—	—	—	—	—	—	—	—	—	30,780	—
—	—	—	—	—	—	—	—	—	—	—	24,61
—	—	—	—	—	—	—	—	—	—	19,899	—
—	$—	—	$—	—	$—	—	$—	—	$—	$427,246	$29,92
—	—	—	—	—	—	—	—	—	—	250	—
—	—	—	—	—	—	—	—	—	—	5,625	—
534,694	8,662	—	—	—	—	26,200,114	424,459	—	—	(433,121)	—
441,014	—	3,841,719	94,869	—	—	17,767,874	388,408	—	—	—	—
—	—	—	—	—	—	—	10,797	—	—	—	—

—	(678)	—	(1,652)	—	—	—	(31,545)	—	—	—	—
—	—	—	—	—	—	—	(731)	—	—	—	—
—	—	(5,165)	(125)	—	—	5,165	125	—	—	—	—
—	(955)	—	3,063	—	—	—	(54,260)	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	(8,36
975,708	$7,029	3,836,554	$96,155	—	$—	43,973,153	$737,253	—	$—	$—	$21,56
392,350	—	—	—	3,749,986	85,448	15,259,174	320,017	562,497	1,176	—	—
—	—	—	—	—	—	215,981	—	—	—	—	—
—	—	—	—	—	—	—	12,630	—	—	—	—
—	(5,891)	—	(8,018)	—	(2,100)	—	(108,923)	—	—	—	—

—	—	—	—	—	—	—	(1,939)	—	—	—	—
—	3,344	—	8,402	—	3,590	—	(106,581)	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	4,130
1,368,058	$4,482	3,836,554	$96,539	3,749,986	$86,938	59,448,308	$852,457	562,497	$1,176	$—	$25,69

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31, 2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(91,245)	$(51,902)	$19,899
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	136,763	52,582	30,869
Asset impairment	38,014	9,507	6,995
Non-cash (gain)/loss on derivative value, net	(10,050)	(21,165)	36,171
(Gain)/loss on asset sales and disposal	987	6,980	(87)
Non-cash compensation expense	12,680	10,828	—
Amortization of deferred financing costs	9,560	1,820	—
Changes in operating assets and liabilities:			
Accounts receivable and prepaid expenses and other	7,416	(35,835)	(32,203)
Accounts payable and accrued liabilities	18,775	43,671	9,793
Net cash provided by operating activities	122,900	16,486	71,437
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(263,537)	(127,226)	(47,324)
Net cash paid for acquisitions	(717,795)	(516,670)	—
Other	(3,222)	(382)	(185)
Net cash used in investing activities	(984,554)	(644,278)	(47,509)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facilities	942,000	667,099	—
Repayments under credit facilities	(874,425)	(315,674)	—
Net proceeds from issuance of long-term debt	510,396	—	—
Net investment from owners	—	5,625	30,780
Distributions paid to unitholders	(124,932)	(33,875)	—
Net proceeds from issuance of Class C preferred limited partner units and warrants	86,624	—	—
Net proceeds from issuance of common limited partner units	320,017	290,115	—
Deferred financing costs, distribution equivalent rights and other	(19,386)	(17,018)	—
Net cash provided by financing activities	840,294	596,272	30,780
Net change in cash and cash equivalents	(21,360)	(31,520)	54,708
Cash and cash equivalents, beginning of year	23,188	54,708	—
Cash and cash equivalents, end of year	$1,828	$23,188	$54,708

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 Delaware 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. The Partnership sponsors and manages tax-advantaged investment partnerships (“Drilling Partnerships”), in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities. At December 31, 2013, Atlas Energy, L.P. (“ATLS”), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of the general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 36.9% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

The Partnership was formed in October 2011 to own and operate substantially all of ATLS’ exploration and production assets (“Atlas Energy E&P Operations”), which were transferred to the Partnership on March 5, 2012. In February 2012, the board of ATLS’ general partner approved the distribution of approximately 5.24 million of the Partnership’s common units which were distributed on March 13, 2012 to ATLS’ unitholders using a ratio of 0.1021 of the Partnership’s limited partner units for each of ATLS’ common units owned on the record date of February 28, 2012.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership’s consolidated balance sheets at December 31, 2013 and 2012, the consolidated statement of operations for the year ended December 31, 2013 and the portion of the consolidated statement of operations for the year ended December 31, 2012 subsequent to the transfer of assets on March 5, 2012 include the accounts of the Partnership and its wholly-owned subsidiaries. The portion of the consolidated statement of operations for the year ended December 31, 2012 prior to the transfer of assets on March 5, 2012 and the consolidated statement of operations for the year ended December 31, 2011 were derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if the Partnership had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all of the various entities comprising Atlas E&P Operations prior to the date of transfer, ATLS’ net investment is shown as equity in the consolidated financial statements. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management's best estimates, in order to derive the financial statements of the Partnership for the periods presented prior to March 5, 2012. Actual balances and results could be different from those estimates. 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. Certain amounts in the prior year's consolidated financial statements have been reclassified to conform to the current year presentation.

On February 17, 2011, ATLS acquired certain natural gas and oil properties, the partnership management business, and other assets ("Transferred Business") from Atlas Energy, Inc. ("AEI"), the former owner of ATLS' general partner (see Note 3). Management of ATLS 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/equity on the Partnership's 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 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 year financial statements to furnish comparative information. As such, the Partnership reflected the impact of the acquisition of the Transferred Business on its 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/equity;

- Retrospectively adjusted its consolidated financial statements for any date prior to February 17, 2011, the date of acquisition, to reflect its 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 its 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. The Partnership has 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 believes the methodology is reasonable and reflects the approximate general and administrative costs of its underlying business segments.

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 energy partnerships in which the Partnership has an interest ("the Drilling Partnerships"). 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 as further explained under the heading "Property, Plant and Equipment" elsewhere within this note.

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. Such estimates included estimated allocations made from the historical accounting records of AEI in order to derive the historical financial statements of the Partnership for periods prior to March 5, 2012. Actual results could differ from those estimates.

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. In evaluating the realizability of its accounts receivable, the Partnership’s management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer’s current creditworthiness, as determined by management’s review of the Partnership’s customers’ credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At December 31, 2013 and 2012, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $4.6 million and $5.3 million of inventory at December 31, 2013 and 2012, 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.

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 which 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 which 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 Long-Lived Assets

The Partnership reviews its long-lived 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 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 futures 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 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 the limited partners in the Drilling Partnerships paying to the Partnership their proportionate share of these expenses plus a profit margin. 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 partner 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.

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, 2013, the Partnership recognized $13.5 million of asset impairments related to its 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 years ended December 31, 2012 and 2011.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2013, the Partnership recognized $24.5 million of asset impairments related to its 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 year ended December 31, 2012, the Partnership recognized $9.5 million of asset impairments related to gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara shales. During the year ended December 31, 2011, the Partnership recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Niobrara Shale.

These impairments related to the carrying amounts of these gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2013, 2012 and 2011 and management's intention not to drill on certain expiring unproved acreage. The estimate of the fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

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 6.0% and 3.5% for the years ended December 31, 2013 and 2012, respectively. The aggregate amount of interest capitalized by the Partnership was $14.2 million and $2.1 million for the years ended December 31, 2013 and 2012, respectively. There was no interest capitalized during the year ended December 31, 2011.

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 following table reflects the components of intangible assets being amortized at December 31, 2013 and 2012 (in thousands):

	December 31,		Estimated Useful Lives In Years
	2013	2012	
Gross Carrying Amount	$14,344	$14,344	13
Accumulated Amortization	(13,381)	(13,024)	
Net Carrying Amount	$963	$1,320	

Amortization expense on intangible assets was $0.4 million, $0.2 million and $0.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2014 - $0.3 million; 2015 - $0.2 million; 2016 - $0.1 million, 2017 - $0.1 million and 2018 - $0.1 million.

Goodwill

At December 31, 2013 and 2012, the Partnership had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions. No changes in the carrying amount of goodwill were recorded for the years ended December 31, 2013, 2012 and 2011.

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 and the available market data of the industry group. 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. During the years ended December 31, 2013, 2012 and 2011, no impairment indicators arose, and no goodwill impairments were recognized by the Partnership.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates (see Note 9). 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.

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 7). 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 accompanying 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 accompanying 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, 2013, 2012 and 2011.

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 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2013.

Stock-Based Compensation

The Partnership recognizes all share-based payments to employees, including grants of employee stock options, in the consolidated financial statements based on their fair values (see Note 15).

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 14), 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.

Prior to the transfer of assets to the Partnership on March 5, 2012 (see Note 1), the Partnership had no common units or General Partner Class A units outstanding. In addition, the Partnership had no net income (loss) attributable to common limited partners and the general partner prior to March 5, 2012.

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 when considered in the calculation of earnings per unit under the two-class method. 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 share-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 15), 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 loss attributable to common limited partners per unit (in thousands, except unit data):

	Years Ended December 31,		
	2013	2012	2011
Net income (loss)	$(91,245)	$(51,902)	$19,899
Income applicable to owner's interest (period prior to transfer of assets on March 5, 2012)	—	(250)	(19,899)
Preferred limited partner dividends	(11,992)	(3,063)	—
Net loss attributable to common limited partners and the general partner	(103,237)	(55,215)	—
Less: General partner's interest	(3,344)	955	—
Net loss attributable to common limited partners	(106,581)	(54,260)	—
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	$(106,581)	$(54,260)	$—

(1) Net income 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, 2013 and 2012, net loss attributable to common limited partners' ownership interest is not allocated to approximately 900,000 and 688,000 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.

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 method. 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 15).

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,		
	2013	2012	2011
Weighted average number of common limited partner units - basic	52,528	34,039	—
Add effect of dilutive incentive awards[1]	—	—	—
Add effect of dilutive convertible preferred limited partner units and warrants[2]	—	—	—
Weighted average number of common limited partner units - diluted	52,528	34,039	—

(1) For the years ended December 31, 2013 and 2012, approximately 900,000 units and 688,000 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, 2013 and 2012, potential common limited partner units issuable upon (a) conversion of the Partnership's Class B and 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.

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, 2013 and 2011. During the year ended December 31, 2012, one of the Partnership's subsidiaries entered into two agreements with the United States Environmental Protection Agency (the "EPA") to settle alleged violations in connection with a fire that occurred at a natural gas well and associated well pad site in Washington County, Pennsylvania in 2010. The EPA alleged non-compliance with the Clean Air Act, including with respect to the storage and handling of the natural gas condensate, as well as non-compliance with the Emergency Planning and Community Right-to-Know Act of 1986. The subsidiary agreed to a civil penalty of $84,506 under a consent agreement and agreed to upgrade its facility pursuant to an administrative settlement agreement.

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, 2013 and 2012, the Partnership had $15.1 million and $37.0 million, respectively, in deposits at various banks, of which $13.4 million and $35.1 million, respectively, were over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments to date.

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, 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. For the year ended December 31, 2012, the Partnership had two customers within its gas and oil production segment that individually accounted for approximately 43% and 11% of the Partnership's natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2011, the Partnership had three customers within its gas and oil production segment that individually accounted for approximately 17%, 14% and 10%, respectively, of the Partnership natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity.

Revenue Recognition

Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Partnership contracts with the Drilling Partnerships to drill partnership wells. The contracts require that the Drilling Partnerships pay the Partnership the full contract price upon execution. The income from a drilling contract is recognized as the services are performed using the percentage of completion method. The contracts are typically completed between 60 and 270 days. On an uncompleted contract, the Partnership classifies the difference between the contract payments it has received and the revenue earned as a current liability titled “Liabilities Associated with Drilling Contracts” on the Partnership’s consolidated balance sheets. The Partnership recognizes well services revenues at the time the services are performed. The Partnership is also entitled to receive management fees according to the respective partnership agreements and recognizes such fees as income when earned, which are included in administration and oversight revenues within its consolidated statements of operations.

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.

The Partnership accrues 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 from the Partnership's records 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, 2013 and 2012 of $55.3 million and $33.4 million, respectively, which were included in accounts receivable within the Partnership's consolidated balance sheets.

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 Shale and the Chattanooga Shale. 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%.

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 at December 31, 2013, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 9). The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss).

Recently Adopted Accounting Standards

In July 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2013-10, Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes ("Update 2013-10"), which amends Accounting Standards Codification Topic 815. Topic 815 provides guidance on the risks that are permitted to be hedged in a fair value or cash flow hedge. In addition, Topic 815 specifies that only the interest rates on direct Treasury obligations of the U.S. Government ("UST") and the London Interbank Offered Rate ("LIBOR") swap rate are considered benchmark interest rates. Update 2013-10 amends Topic 815 to include the Overnight Index Swap Rate ("OIS"), also referred to as the Fed Funds Effective Swap Rate, as a U.S. benchmark interest rate for hedge accounting purposes. Including the OIS as an acceptable U.S. benchmark interest rate in addition to UST and LIBOR will provide risk managers with a more comprehensive spectrum of interest rate resets to utilize as the designated benchmark interest rate risk component under the hedge accounting guidance in Topic 815. Update 2013-10 is effective for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. The Partnership adopted the requirements of Update 2013-10 upon its effective date of July 17, 2013, and it had no material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220) ("Update 2013-02"). Update 2013-02 requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present significant amounts reclassified out of accumulated other comprehensive income if the amount reclassified to net income in its entirety is in the same reporting period as incurred. For other amounts that are not required to be reclassified in their entirety to net income, an entity is required to reference to other disclosures that provide additional detail about those amounts. Entities are required to implement the amendments prospectively for reporting periods beginning after December 15, 2012, with early adoption being permitted. The Partnership adopted the requirements of Update 2013-02 upon its effective date of January 1, 2013, and it had no material impact on its financial position, results of operations or related disclosures.

In January 2013, the FASB issued ASU 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities ("Update 2013-01"). Update 2013-01 clarifies that ordinary trade receivables and receivables are not in scope of ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. Specifically, ASU 2011-11 applies only to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in the FASB Accounting Standards Codification or subject to a master netting arrangement or similar agreement. The amendments are effective for interim and annual reporting periods beginning after January 1, 2013 and such amendments shall be applied retrospectively for any period presented that begins before the date of application. The Partnership adopted the requirements of Update 2013-01 on December 31, 2012, and it did not have a material impact on its financial position, results of operations or related disclosures.

In July 2012, the FASB issued ASU 2012-02, Intangibles – Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment ("Update 2012-02"). The amendments in Update 2012-02 allow an entity to first assess qualitative factors to determine whether the existence of events and circumstances indicates that it is more likely than not that the indefinite-lived intangible asset is impaired. The "more likely than not" threshold is defined as having a likelihood of more than 50%. If, after assessing qualitative factors, an entity determines it is not likely that the indefinite-lived intangible asset is impaired, then no further action is required. If impairment is deemed more likely than not, the entity is required to determine the fair value of the indefinite-lived intangible asset and perform the quantitative impairment test by comparing the fair value with the carrying amount of the asset. Additionally, under the amendments in Update 2012-02, an entity has the option to bypass the qualitative assessment for any indefinite-lived intangible asset in any period and proceed directly to performing the quantitative impairment test. An entity will be able to resume performing the qualitative assessment in any subsequent period. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption being permitted. The Partnership adopted the requirements of Update 2012-02 upon its effective date of January 1, 2013, and it had no material impact on its financial position, results of operations or related disclosures.

Recently Issued Accounting Standards

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) – Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists ("Update 2013-11"), which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership will apply the requirements of Update 2013-11 upon its effective date of January 1, 2014, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date ("Update 2013-04"). Update 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements, for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations and settled litigation and judicial rulings. Update 2013-04 requires an entity to measure joint and several liability arrangements, for which the total amount of the obligation is fixed at the reporting date as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, Update 2013-04 provides disclosure guidance on the nature and amount of the obligation as well as other information. Update 2013-04 is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. The Partnership will apply the requirements of Update 2013-04 upon its effective date of January 1, 2014, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

NOTE 3 – ATLAS ENERGY, L.P. ACQUISITION FROM ATLAS ENERGY, INC.

On February 17, 2011, ATLS acquired the Transferred Business from AEI, including the following exploration and production assets that were transferred to the Partnership on March 5, 2012:

- AEI's investment management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which the Partnership funds a portion of its natural gas and oil well drilling;

- proved reserves located in the Appalachian Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan and the Chattanooga Shale of northeastern Tennessee; and

- certain producing natural gas and oil properties, upon which the Partnership is the developer and producer.

Concurrent with ATLS' acquisition of the Transferred Business, AEI was sold to Chevron Corporation (NYSE: CVX; "Chevron"). In connection with the transaction, ATLS received $118.7 million with respect to a contractual cash transaction adjustment from AEI related to certain exploration and production liabilities assumed by ATLS. Including the cash transaction adjustment, the net book value of the Transferred Business was approximately $522.9 million. Certain amounts included within the contractual cash transaction adjustment were subject to a reconciliation period with Chevron following the consummation of the transaction. Liabilities related to the cash transaction adjustment were assumed by the Partnership on March 5, 2012, as certain amounts included within the contractual cash transaction adjustment remained in dispute between the parties. During the year ended December 31, 2012, the Partnership recognized a $7.7 million charge on its consolidated statement of operations regarding its reconciliation process with Chevron, which was settled in October 2012.

Management of ATLS determined that the acquisition of the Transferred Business constituted a transaction between entities under common control. As such, ATLS recognized the assets acquired and liabilities assumed at historical carrying value at the date of acquisition, with the difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital on its consolidated combined balance sheet. ATLS recognized a non-cash decrease of $261.0 million in partners' capital on its consolidated combined balance sheet based on the excess net book value above the value of the consideration paid to AEI. The following table presents the historical carrying value of the assets acquired and liabilities assumed by ATLS, including the effect of cash transaction adjustments, as of February 17, 2011 (in thousands):

Cash	$153,350
Accounts receivable	18,090
Accounts receivable – affiliate	45,682
Prepaid expenses and other	6,955
Total current assets	224,077

Property, plant and equipment, net	516,625
Goodwill	31,784
Intangible assets, net	2,107
Other assets, net	20,416
Total long-term assets	570,932
Total assets acquired	$795,009
Accounts payable	$59,202
Net liabilities associated with drilling contracts	47,929
Accrued well completion costs	39,552
Current portion of derivative payable to Drilling Partnerships	25,659
Accrued liabilities	25,283
Total current liabilities	197,625
Long-term derivative payable to Drilling Partnerships	31,719
Asset retirement obligations	42,791
Total long-term liabilities	74,510
Total liabilities assumed	$272,135
Historical carrying value of net assets acquired	$522,874

The Partnership reflected the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which the Transferred Business was acquired and retrospectively adjusted its prior year financial statements to furnish comparative information (see Note 2).

NOTE 4 – ACQUISITIONS

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 8), and the issuance of 14,950,000 common limited partner units and 3,749,986 newly created Class C convertible preferred units (see Note 13). 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 accompanying consolidated financial statements reflect the operating results of the acquired business commencing July 31, 2013.

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 10). 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. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

The following table presents the preliminary 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:	
Property, plant and equipment	$728,925
Liabilities:	
Accounts payable	2,562
Asset retirement obligation	16,728
Total liabilities assumed	19,290
Net assets acquired	$709,635

Revenues and net loss of $66.1 million and $5.2 million, respectively, have been included in the Partnership's consolidated statement of operations related to the EP Energy Acquisition for year ended December 31, 2013.

DTE Acquisition

On December 20, 2012, the Partnership completed the acquisition of DTE Gas Resources, LLC from DTE Energy Company (NYSE: DTE; "DTE") for $257.4 million (the "DTE Acquisition"). In connection with entering into a purchase agreement related to the DTE Acquisition, the Partnership issued approximately 7.9 million of its common limited partner units through a public offering in November 2012 for $174.5 million, which was used to partially repay amounts outstanding under its revolving credit facility prior to closing (see Note 13). The cash paid at closing was funded through $179.8 million of borrowings under the Partnership's revolving credit facility and $77.6 million through borrowings under its then-existing term loan credit facility (see Note 8).

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 10). In conjunction with the issuance of common units associated with the acquisition, the Partnership recorded $0.2 million of transaction fees within common limited partners' interests for the year ended December 31, 2012 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:	
Accounts receivable	$10,721
Prepaid expenses and other	2,100
Total current assets	12,821
Property, plant and equipment	263,194
Other assets, net	273
Total assets acquired	$276,288
Liabilities:	
Accounts payable	$7,760
Accrued liabilities	2,910
Total current liabilities	10,670
Asset retirement obligation and other	8,169
Total liabilities assumed	18,839
Net assets acquired	$257,449

Titan Acquisition

On July 25, 2012, the Partnership completed the acquisition of Titan Operating, L.L.C. ("Titan") in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had an estimated collective value of $193.2 million, based upon the closing price of the Partnership's publicly traded units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Note 13). The cash paid at closing was funded through borrowings under the Partnership's credit facility. The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the "Securities Act") (see Note 13). The Partnership's acquisition of Titan in exchange for 3.8 million common units and 3.8 million newly created convertible Class B preferred units represented a non-cash transaction during the year ended December 31, 2012.

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 10). In conjunction with the issuance of common and preferred limited partner units associated with the acquisition, the Partnership recorded $3.5 million of transaction fees within common and preferred limited partners' interests for the year ended December 31, 2012 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

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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:	
Cash and cash equivalents	$372
Accounts receivable	5,253
Prepaid expenses and other	131
Total current assets	5,756
Property, plant and equipment	208,491
Other assets, net	2,344
Total assets acquired	$216,591
Liabilities:	
Accounts payable	$676
Revenue distribution payable	3,091
Accrued liabilities	1,816
Total current liabilities	5,583
Asset retirement obligation and other	2,418
Total liabilities assumed	8,001
Net assets acquired	$208,590

Carrizo Acquisition

On April 30, 2012, the Partnership completed the acquisition of certain oil and natural gas assets from Carrizo Oil and Gas, Inc. (NASDAQ: CRZO; “Carrizo”) for approximately $187.0 million in cash (the “Carrizo Acquisition”). The purchase price was funded through borrowings under the Partnership’s credit facility and $119.5 million of net proceeds from the sale of 6.0 million of its common units at a negotiated purchase price per unit of $20.00, of which $5.0 million was purchased by certain executives of the Partnership. The common units were issued in a private transaction exempt from registration under Section 4(2) of the Securities Act (see Note 13). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $1.2 million of transaction fees within common limited partners’ interests for the year ended December 31, 2012 on the Partnership’s consolidated balance sheet.

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 10).

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:	
Property, plant and equipment	$190,946
Liabilities:	
Asset retirement obligation	3,903
Net assets acquired	$187,043

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 EP Energy, DTE, Titan and Carrizo acquisitions, including the related borrowings, net proceeds from the issuance of debt and issuances of common and preferred units had occurred on January 1, 2012. 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 EP Energy, DTE, Titan, and Carrizo acquisitions and related offerings had occurred on January 1, 2012 or the results that will be attained in future periods (in thousands, except per unit data; unaudited):

	Years Ended December 31,	
	2013	2012
Total revenues and other	$558,281	$467,483
Net loss	(51,065)	(122,734)
Net loss attributable to common limited partners	(71,734)	(120,276)
Net loss attributable to common limited partners per unit:		
Basic and Diluted	$(1.21)	$(2.04)

Other Acquisitions

In April 2012, the Partnership acquired a 50% interest in approximately 14,500 net undeveloped acres in the oil and NGL area of the Mississippi Lime play in northwestern Oklahoma for $18.0 million from subsidiaries of Equal Energy, Ltd. (NYSE: EQU; TSX: EQU; “Equal”). The transaction was funded through borrowings under the Partnership’s revolving credit facility. Concurrent with the purchase of acreage, the Partnership and Equal entered into a participation and development agreement for future drilling in the Mississippi Lime play. The Partnership served as the drilling and completion operator, while Equal undertook production operations, including water disposal. In September 2012, the Partnership acquired Equal’s remaining 50% interest in the undeveloped acres, as well as approximately 8 MMcfed of net production in the Mississippi Lime region and salt water disposal infrastructure for $41.3 million, including $1.3 million related to certain post-closing adjustments. Both transactions were financed through borrowings under the Partnership’s revolving credit facility. As a result of the Partnership’s acquisition of Equal’s remaining interest in the undeveloped acres, the existing joint venture agreement between the Partnership and Equal in the Mississippi Lime position was terminated and all infrastructure associated with the assets, principally the salt water disposal system, is operated by the Partnership.

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 5 – PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment at the dates indicated (in thousands):

	December 31, 2013	December 31, 2012	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$320,459	$244,476	
Pre-development costs	4,367	1,935	
Wells and related equipment	2,164,760	1,222,475	
Total proved properties	2,489,586	1,468,886	
Unproved properties	211,536	292,053	
Support equipment	23,005	13,110	
Total natural gas and oil properties	2,724,127	1,774,049	
Pipelines, processing and compression facilities	42,949	33,092	2 – 40
Rights of way	830	784	20 – 40
Land, buildings and improvements	9,462	8,283	3 – 40
Other	15,318	9,762	3 – 10
	2,792,686	1,825,970	
Less – accumulated depreciation, depletion and amortization	(671,868)	(523,742)	
	$2,120,818	$1,302,228	

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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.

During the year ended December 31, 2012, the Partnership recognized a $7.0 million loss on asset disposal, pertaining to its decision to terminate a farm out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm out agreement contained certain well drilling targets for the Partnership to maintain ownership of the South Knox processing plant, which the Partnership's management decided in 2012 not to achieve due to the then current natural gas price environment. As a result, the Partnership's management forfeited its interest in the processing plant and related properties and recorded a loss related to the net book values of those assets during the year ended December 31, 2012.

During the year ended December 31, 2013, the Partnership recognized $38.0 million of asset impairments related to its oil and gas properties within property, plant and equipment, net on its consolidated balance sheet primarily for its shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany shales. During the year ended December 31, 2012, the Partnership recognized $9.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara shales. During the year ended December 31, 2011, the Partnership recognized $7.0 million of asset impairment related to its gas and oil properties within property, plant and equipment, net on its combined balance sheet for its shallow natural gas wells in the Niobrara Shale. These impairments related to the carrying amounts of gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2013, 2012 and 2011 and management's 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 natural gas prices at the date of measurement.

NOTE 6 – OTHER ASSETS

The following is a summary of other assets at the dates indicated (in thousands):

	December 31, 2013	2012
Deferred financing costs, net of accumulated amortization of $11,948 and $2,388 at December 31, 2013 and 2012, respectively	$35,292	$14,467
Notes receivable	3,978	—
Other	2,688	1,655
	$41,958	$16,122

Deferred financing costs are recorded at cost and amortized over the term of the respective debt agreements (see Note 8). Amortization expense of deferred financing costs was $6.4 million and $1.8 million for the years ended December

31, 2013 and 2012, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. There was no amortization expense of deferred financing costs during the year ended December 31, 2011. 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 (see Note 8). There was no accelerated amortization of deferred financing costs during the years ended December 31, 2012 and 2011.

At December 31, 2013, 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 sheet. 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 the year ended December 31, 2013, $0.1 million of interest income was recognized within other, net on the Partnership's consolidated statements of operations. There was no interest income recognized for the years ended December 31, 2012 and 2011. At December 31, 2013, 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 7 – ASSET RETIREMENT OBLIGATIONS

The Partnership recognized an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities. The Partnership also recognized a liability for its 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. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability for asset retirement obligations was based on the Partnership's 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 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, 2013, the Drilling Partnerships had $59.7 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. During the year ended December 31, 2013, the Partnership withheld $0.3 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. No amounts were withheld during the years ended December 31, 2012 and 2011. 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):

Years Ending December 31,

	2013	2012	2011
Asset retirement obligations, beginning of year	$64,794	$45,779	$42,673
Liabilities incurred	21,786	16,568	713
Liabilities settled	(1,188)	(546)	(209)
Accretion expense	4,384	2,993	2,602
Asset retirement obligations, end of year	$89,776	$64,794	$45,779

The above accretion expense was included in depreciation, depletion and amortization in the Partnership’s consolidated statements of operations and the asset retirement obligation liabilities were included within asset retirement obligations and other in the Partnership’s consolidated balance sheets. During the year ended December 31, 2013, the Partnership incurred $16.7 million of future plugging and abandonment costs related to the EP Energy Acquisition it consummated during the period. During the year ended December 31, 2012, the Partnership incurred $15.6 million of future plugging and abandonment costs related to acquisitions it consummated during the period (see Note 4).

NOTE 8 - DEBT

Total debt consists of the following at the dates indicated (in thousands):

	December 31,	
	2013	2012
Revolving credit facility	$419,000	$276,000
Term loan credit facility	—	75,425
7.75 % Senior Notes – due 2021	275,000	—
9.25 % Senior Notes – due 2021	248,334	—
Total debt	942,334	351,425
Less current maturities	—	—
Total long-term debt	$942,334	$351,425

Credit Facility

On July 31, 2013, in connection with the EP Energy Acquisition (see Note 4), the Partnership entered into a Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the "Credit Agreement"), which amended and restated the Partnership's existing revolving credit facility. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks scheduled to mature in July 2018. The Partnership's borrowing base is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. On December 6, 2013, the Partnership entered into the First Amendment to the Credit Agreement (the "Amendment"). The Amendment redetermined the borrowing base to $735.0 million and amended the ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable). The Credit Agreement has a maximum facility amount of $1.5 billion. At December 31, 2013, $419.0 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 $3.6 million was outstanding at December 31, 2013. 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 1.75% and 2.75% per annum 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 0.75% and 1.75% per annum. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.5% per annum if 50% or more of the borrowing base is utilized and 0.375% per annum if less than 50% of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At December 31, 2013, the weighted average interest rate on outstanding borrowings under the credit facility was 2.4%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of December 31, 2013. The Credit Agreement also requires the Partnership to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended December 31, 2013, March 31, 2014 and June 30, 2014, 4.25 to 1.0 as of the last day of the quarter ending September 30, 2014, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter 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. Based on the definitions contained in the Partnership's Credit Agreement, at December 31, 2013, the Partnership's ratio of current assets to current liabilities was 1.9 to 1.0, and its ratio of Total Funded Debt to EBITDA was 4.0 to 1.0.

Senior Notes

On July 30, 2013, the Partnership issued $250.0 million of its 9.25% Senior Notes, due 2021, in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million. The net proceeds were used to partially fund the EP Energy Acquisition (see Note 4). The 9.25% Senior Notes were presented net of a $1.7 million unamortized discount as of December 31, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date on February 15, 2014. 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%. In addition, at any time prior to August 15, 2016, the Partnership may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. 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.

In connection with the issuance of the 9.25% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (the "SEC") to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 30, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, the Partnership has agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If the Partnership fails to comply with its obligations to register the 9.25% Senior Notes within the specified time periods, the 9.25% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable.

On January 23, 2013, the Partnership issued $275.0 million of its 7.75% Senior Notes, due 2021, in a private placement transaction at par. The Partnership used the net proceeds of approximately $267.6 million to repay all of the indebtedness and accrued interest outstanding under its then-existing term loan credit facility and a portion of the amounts outstanding under its revolving credit facility. In connection with the retirement of the Partnership's term loan credit facility and the reduction in its revolving credit facility borrowing base, the Partnership accelerated $3.2 million of amortization expense related to deferred financing costs during the year ended December 31, 2013 (see Note 6). 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 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 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing 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.

On July 1, 2013, the Partnership filed a registration statement relating to the exchange offer for the 7.75% Senior Notes and the exchange offer was completed on January 2, 2013.

The 9.25% Senior Notes and 7.75% Senior Notes are guaranteed by certain of the Partnership's material subsidiaries. The guarantees under the 9.25% Senior Notes and 7.75% Senior Notes are full and unconditional and joint and several, 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 9.25% Senior Notes and 7.75% Senior Notes contain covenants, including limitations of 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, 2013.

The aggregate amount of the Partnership’s debt maturities is as follows (in thousands):

Years Ended December 31:	
2014	$—
2015	—
2016	—
2017	—
2018	419,000
Thereafter	525,000
Total principle maturities	944,000
Unamortized discounts	(1,666)
Total debt	$942,334

Cash payments for interest by the Partnership were $17.9 million and $3.1 million for the years ended December 31, 2013 and 2012, respectively. There were no cash payments for interest for the year ended December 31, 2011.

NOTE 9 – 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. 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.

Management formally documents all relationships between the Partnership’s hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching the commodity derivative contracts to the forecasted transactions. Management assesses, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying item being hedged, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which are determined by management of the Partnership through the utilization of market data, will be recognized immediately within other, net in the Partnership's consolidated statements of operations. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value of derivative instruments as accumulated other comprehensive income and reclassifies the portion relating to commodity derivatives to gas and oil production revenues within the Partnership's consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, management recognizes changes in fair value within other, net in the Partnership's consolidated statements of operations as they occur.

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 reflected net derivative assets on its consolidated balance sheets of $22.6 million and $20.3 million at December 31, 2013 and 2012, respectively. Of the $25.7 million of net gain in accumulated other comprehensive income on the Partnership's consolidated balance sheet at December 31, 2013, if the fair values of the instruments remain at current market values, the Partnership will reclassify $4.7 million of losses to gas and oil production revenue on its consolidated statement of operations over the next twelve month period as these contracts expire. Aggregate gains of $30.4 million of gas and oil production revenues will be reclassified to the Partnership's consolidated statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future commodity price changes. Approximately $3.4 million of derivative gains were reclassified from other comprehensive income related to derivative instruments entered into during the year ended December 31, 2013.

The following table summarizes the gains recognized in the Partnership's consolidated statements of operations for effective derivative instruments for the periods indicated (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Gain reclassified from accumulated other comprehensive income:			
Gas and oil production revenue	$(9,722)	$(19,281)	$(10,542)
Total	$(9,722)	$(19,281)	$(10,542)

The following table summarizes the gross fair values of the Partnership's derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on the Partnership's consolidated balance sheets for the periods indicated (in thousands):

Offsetting Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Assets Presented in the Consolidated Balance Sheets
As of December 31, 2013			
Current portion of derivative assets	$ 2,664	$ (773)	$ 1,891
Long-term portion of derivative assets	31,146	(4,062)	27,084
Current portion of derivative liabilities	4,341	(4,341)	—
Long-term portion of derivative liabilities	122	(122)	—
Total derivative assets	$ 38,273	$ (9,298)	$ 28,975
As of December 31, 2012			
Current portion of derivative assets	$ 14,248	$ (1,974)	$ 12,274
Long-term portion of derivative assets	14,724	(5,826)	8,898
Long-term portion of derivative liabilities	800	(800)	—
Total derivative assets	$ 29,772	$ (8,600)	$ 21,172

Offsetting Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Balance Sheets
As of December 31, 2013			
Current portion of derivative assets	$ (773)	$ 773	$ —
Long-term portion of derivative assets	(4,062)	4,062	—
Current portion of derivative liabilities	(10,694)	4,341	(6,353)
Long-term portion of derivative liabilities	(189)	122	(67)
Total derivative liabilities	$ (15,718)	$ 9,298	$ (6,420)
As of December 31, 2012			

Current portion of derivative assets	$ (1,974)	$ 1,974	$ —
Long-term portion of derivative assets	(5,826)	5,826	—
Long-term portion of derivative liabilities	(1,688)	800	(888)
Total derivative liabilities	$ (9,488)	$ 8,600	$ (888)

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 New York Mercantile Exchange (“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 have qualified and been designated as cash flow hedges and were recorded at their fair values.

In June 2012, the Partnership received approximately $3.9 million in net proceeds from the early termination of natural gas and oil derivative positions for production periods from 2015 through 2016. In conjunction with the early termination of these derivatives, the Partnership entered into new derivative positions at prevailing prices at the time of the transaction. The net proceeds from the early termination of these derivatives were used to reduce indebtedness under the Partnership’s credit facility (see Note 8). The gain recognized upon the early termination of these derivative positions will continue to be reported in accumulated other comprehensive income and will be reclassified into the Partnership’s consolidated statements of operations in the same periods in which the hedged production revenues would have been recognized in earnings.

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 4). 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 were fully amortized as of September 30, 2013. Swaption premiums paid are amortized over the period from initiation of the contract through 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.

During the year ended December 31, 2012, the Partnership entered into swaptions contracts up through May 31, 2012 for production volumes related to wells acquired from Carrizo (see Note 4). In connection with the swaption contracts, the Partnership paid premiums of $4.6 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 were fully amortized as of June 30, 2012. For the year ended December 31, 2012, the Partnership recorded approximately $4.6 million of amortization expense in other, net on the Partnership’s consolidated statement of operations related to the swaption contracts.

The Partnership recognized gains of $9.7 million, $19.3 million and $10.5 million for the years ended December 31, 2013, 2012 and 2011, respectively, on settled contracts covering commodity production. These gains 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, 2013, 2012 and 2011 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At December 31, 2013, 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/(Liability) (in thousands)(2)
2014	60,153,000	$ 4.152	$ (2,238)
2015	51,474,500	$ 4.236	4,639
2016	45,746,300	$ 4.311	8,183
2017	24,840,000	$ 4.532	9,053
2018	3,960,000	$ 4.716	1,819
			$ 21,456

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)	Fair Value Asset/ (Liability) (in thousands)(2)
2014	Puts purchased	3,840,000	$ 4.221	$ 1,322
2014	Calls sold	3,840,000	$ 5.120	(363)
2015	Puts purchased	3,480,000	$ 4.234	1,747
2015	Calls sold	3,480,000	$ 5.129	(639)
				$ 2,067

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)
2014	Puts purchased	1,800,000	$ 3.800	$ 222
2015	Puts purchased	1,440,000	$ 4.000	486
2016	Puts purchased	1,440,000	$ 4.150	667
				$ 1,375

Natural Gas Liquids Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Asset/ (Liability) (in thousands)(3)
2014	105,000	$ 91.571	$ (417)
2015	96,000	$ 88.550	44
2016	84,000	$ 85.651	183
2017	60,000	$ 83.780	186
			$ (4)

Natural Gas Liquids Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(4)
2014	2,520,000	$ 0.303	$ 67
			$ 67

Natural Gas Liquids Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Liability (in thousands)(5)

2014	12,348,000	$ 0.996	$ (1,409)
2015	8,064,000	$ 1.016	(144)
			$ (1,553)

Natural Gas Liquids Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Liability (in thousands)(6)
2014	1,512,000	$ 1.308	$ (27)
2015	1,512,000	$ 1.248	(70)
			$ (97)

Natural Gas Liquids Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Liability (in thousands)(7)
2014	1,512,000	$ 1.323	$ (7)
2015	1,512,000	$ 1.263	(99)
			$ (106)

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Asset/ (Liability) (in thousands)(3)
2014	552,000	$ 92.668	$ (1,657)
2015	567,000	$ 88.144	51
2016	225,000	$ 85.523	463
2017	132,000	$ 83.305	348
			$ (795)

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)(1)	Average Floor and Cap (per Bbl)(1)	Fair Value Asset/ (Liability) (in thousands)(3)
2014	Puts purchased	41,160	$ 84.169	$ 79
2014	Calls sold	41,160	$ 113.308	(36)
2015	Puts purchased	29,250	$ 83.846	158
2015	Calls sold	29,250	$ 110.654	(56)
				$ 145
Total net assets				$ 22,555

(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.

(4) Fair value based on forward Mt. Belvieu ethane prices, as applicable.
(5) Fair value based on forward Mt. Belvieu propane prices, as applicable.
(6) Fair value based on forward Mt. Belvieu butane prices, as applicable.
(7) Fair value based on forward Mt. Belvieu iso butane prices, as applicable

At December 31, 2013, the Partnership had net cash proceeds of $3.5 million related to hedging positions monetized on behalf of the Drilling Partnerships' limited partners, which were included within cash and cash equivalents on the Partnership's consolidated balance sheet. The Partnership will allocate 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. The Partnership reflected the remaining hedge monetization proceeds within current and long-term portion of derivative payable to Drilling Partnerships on its consolidated balance sheets as of December 31, 2013 and 2012.

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 unrealized 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, 2013, net unrealized derivative assets of $1.4 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At December 31, 2013, 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 8), 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 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 10 – 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 9). 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, 2013 and 2012 was as follows (in thousands):

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Derivative assets, gross				
Commodity swaps	$ —	$33,594	$ —	$33,594
Commodity puts	—	1,374	—	1,374
Commodity options	—	3,305	—	3,305
Total derivative assets, gross	—	38,273	—	38,273
Derivative liabilities, gross				
Commodity swaps	—	(14,624)	—	(14,624)
Commodity options	—	(1,094)	—	(1,094)
Total derivative liabilities, gross	—	(15,718)	—	(15,718)
Total derivatives, fair value, net	$ —	$22,555	$ —	$22,555

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Derivative assets, gross				
Commodity swaps	$ —	$15,859	$ —	$15,859
Commodity puts	—	2,991	—	2,991
Commodity options	—	10,923	—	10,923
Total derivative assets, gross	—	29,773	—	29,773
Derivative liabilities, gross				
Commodity swaps	—	(6,813)	—	(6,813)
Commodity puts	—	—	—	—
Commodity options	—	(2,676)	—	(2,676)
Total derivative liabilities, gross	—	(9,489)	—	(9,489)
Total derivatives, fair value, net	$ —	$20,284	$ —	$20,284

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 value of the Partnership’s long-term debt at December 31, 2013, which consists of its Senior Notes and outstanding borrowings under its revolving credit facility (see Note 8), was $938.6 million compared with the carrying amount of $942.3 million. At December 31 2013 and December 31, 2012, the carrying value of outstanding borrowings under the Partnership’s revolving credit facility (see Note 8), which bears interest at variable interest rates, approximated its estimated fair value. The estimated fair values of the Partnership’s Senior Notes were based upon the market approach and calculated using yields of the Partnership as provided by financial institutions and thus was categorized as a Level 3 value.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Management estimates the fair value of its 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 assets and liabilities that were measured at fair value on a nonrecurring basis for the years ended December 31, 2013 and 2012 were as follows (in thousands):

	Years Ended December 31,			
	2013		2012	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$21,786	$21,786	$16,568	$16,568
Total	$21,786	$21,786	$16,568	$16,568

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. For the years ended December 31, 2013, 2012, and 2011, the Partnership recognized $38.0 million, $9.5 million and $7.0 million, respectively, of impairment of long-lived assets which were defined as a Level 3 fair value measurements (see Note 2 – Impairment of Long-Lived Assets).

During the year ended December 31, 2013, the Partnership completed the acquisitions of certain oil and gas assets from EP Energy (see Note 4). During the year ended December 31, 2012, the Partnership completed the acquisitions of certain oil and gas assets from Carrizo, Titan, Equal and DTE (see Note 4). The fair value measurements of assets acquired and liabilities assumed for each of these acquisitions are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The estimate of fair value of the EP Energy Acquisition as of the respective acquisition date, which are reflected in the Partnership's consolidated balance sheet as of December 31, 2013, are subject to change as the final valuation has not yet been completed, and such changes could be material. 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 7). These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are subject to change.

The fair value of the warrants associated with the Class C preferred units (see Note 13) was measured using a Black-Scholes pricing model which is based on Level 3 inputs including conversion price of $23.10, discount rate of 0.21% and estimated volatility rate of 35%.

NOTE 11 — CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with Drilling Partnerships. The Partnership conducts certain activities through, and a portion of its revenues are attributable to, 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 Atlas Pipeline Partners, L.P. The Partnership's general partner, ATLS, also maintains a general partner ownership interest in Atlas Pipeline Partners, L.P. ("APL"), a publicly traded Delaware master limited partnership (NYSE: APL) and midstream energy service provider engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States. In the Chattanooga Shale, a portion of the natural gas produced by the Partnership is gathered and processed by APL. For the years ended December 31, 2013, 2012 and 2011, $0.3 million, $0.4 million and $0.3 million, respectively, of gathering fees were paid by the Partnership to APL.

In addition, in Lycoming County, Pennsylvania, APL agreed to provide assistance in the design and construction management services for the Partnership with respect to a pipeline. The Partnership reimbursed approximately $1.8 million to APL as of December 31, 2013.

NOTE 12 — COMMITMENTS AND CONTINGENCIES

General Commitments

The Partnership leases office space and equipment under leases with varying expiration dates. Rental expense was $13.1 million, $4.1 million, and $1.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Future minimum rental commitments for the next five years are as follows (in thousands):

Years Ended December 31,	
2014	$3,903
2015	3,064
2016	2,621
2017	2,470
2018	1,592
Thereafter	5,140
	$18,790

The Partnership is the 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. Subject to certain conditions, investor partners in certain Drilling Partnerships have the right to present their interests for purchase by the Partnership, as managing general partner. The Partnership is not obligated to purchase more than 5% to 10% of the units in any calendar year. Based on its historical experience, as of December 31, 2013, the management of the Partnership believes that any such liability incurred would not be material. Also, the Partnership has agreed to subordinate a portion of its share of net partnership revenues from certain of the Drilling Partnerships to the benefit of the investor partners until they have received specified returns, typically 10% to 12% per year determined on a cumulative basis, over a specific period, typically the first five to eight years, in accordance with the terms of the partnership agreements. For the years ended December 31, 2013, 2012 and 2011, $9.6 million, $6.3 million and $4.0 million, respectively, of the Partnership's revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the Drilling Partnerships.

Certain of the Partnership's executives are parties to employment agreements with ATLS that provide compensation and certain other benefits. The agreements also provide for severance payments under certain circumstances.

In connection with the EP Energy Acquisition (see Note 4), 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, 2013 were as follows: 2014—$8.8 million; 2015—$8.6 million; 2016—$2.1 million; and 2017 to 2018—none.

As of December 31, 2013, the Partnership is committed to expend approximately $11.8 million, principally on drilling and completion expenditures and throughput commitments.

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 13 –ISSUANCES OF UNITS

Equity Offerings

In July 2013, in connection with the closing of the EP Energy Acquisition (see Note 4), 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 initial Class C preferred distribution was paid for the quarter ending September 30, 2013. 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.

In June 2013, in connection with entering the EP Energy Acquisition (see Note 4), 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 8).

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. Sales of common limited partner units, if any, could be made in negotiated transactions or transactions that were 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 limited partner units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. The Partnership paid each of the agents a commission, which in each case was not more than 2.0% of the gross sales price of common limited partner units sold through such agent. 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 its equity distribution agreement effective December 27, 2013.

In November and December 2012, in connection with entering into a purchase agreement to acquire certain producing wells and net acreage from DTE, the Partnership sold an aggregate of 7,898,210 of its common limited partner units in a public offering at a price of $23.01 per unit, yielding net proceeds of approximately $174.5 million. The Partnership utilized the net proceeds from the sale to repay a portion of the outstanding balance under its revolving credit facility and $2.2 million under its then-existing term loan credit facility.

In July 2012, the Partnership completed the acquisition of certain proved reserves and associated assets in the Barnett Shale from Titan in exchange for 3.8 million Partnership common units and 3.8 million newly-created convertible Class B preferred units (which have an estimated collective value of $193.2 million, based upon the closing price of the Partnership's publicly traded common units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Note 4). The Class B preferred units are voluntarily convertible to common units on a one-for-one basis within three years of the acquisition closing date at a strike price of $26.03 plus all unpaid preferred distributions per unit, and will be mandatorily converted to common units on the third anniversary of the issuance. While outstanding, the preferred units will receive regular quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

The Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC by January 25, 2013 to register the resale of the common units issued on the acquisition closing date and those issuable upon conversion of the Class B preferred units. The Partnership agreed to use its commercially reasonable efforts to have the registration statement declared effective by March 31, 2013, and to cause the registration statement to be continuously effective until the earlier of (i) the date as of which all such common units registered thereunder are sold by the holders and (ii) one year after the date of effectiveness. On September 19, 2012, the Partnership filed a registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement, and the registration statement was declared effective by the SEC on October 2, 2012.

In April 2012, the Partnership completed the acquisition of certain oil and gas assets from Carrizo (see Note 4). To partially fund the acquisition, the Partnership sold 6.0 million of its common units in a private placement at a negotiated purchase price per unit of $20.00, for net proceeds of $119.5 million, of which $5.0 million was purchased by certain executives of the Partnership. The common units issued by the Partnership are subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that the Partnership would (a) file a registration statement with the SEC by October 30, 2012 and (b) cause the registration statement to be declared effective by the SEC by December 31, 2012. On July 11, 2012, the Partnership filed a registration statement with the SEC for the common units subject to the registration rights agreement in satisfaction of the requirements of the registration rights agreement, and on August 28, 2012, the registration statement was declared effective by the SEC.

Common Unit Distribution

In February 2012, the board of directors of ATLS' general partner approved the distribution of approximately 5.24 million of the Partnership's common limited partner units which were distributed on March 13, 2012 to ATLS' unitholders using a ratio of 0.1021 Partnership common limited partner units for each of ATLS' common units owned on the record date of February 28, 2012.

NOTE 14 – CASH DISTRIBUTIONS

The Partnership has a cash distribution policy under which it distributes, within 45 days following the end of each calendar quarter, all of its available cash (as defined in the partnership agreement) for that quarter to its common unitholders and general partner. 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.

Distributions declared by the Partnership from its formation through December 31, 2013 were as follows (in thousands, except per unit amounts):

Date Cash Distribution Paid	For Quarter 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, 2012	March 31, 2012	$ 0.12 (1)	$ 3,144	$ —	$ 64
August 14, 2012	June 30, 2012	$ 0.40	$ 12,891	$ —	$ 263
November 14, 2012	September 30, 2012	$ 0.43	$ 15,510	$ 1,652	$ 350
February 14, 2013	December 31, 2012	$ 0.48	$ 21,107	$ 1,841	$ 618
May 15, 2013	March 31, 2013	$ 0.51	$ 22,428	$ 1,957	$ 946
August 14, 2013	June 30, 2013	$ 0.54	$ 32,097	$ 2,072	$ 1,884
November 14, 2013	September 30, 2013	$ 0.56	$ 33,291	$ 4,248	$ 2,443

(1) Represents a pro-rated cash distribution of $0.40 per common limited partner unit for the period from March 5, 2012, the date ATLS' exploration and production assets were transferred to the Partnership, to March 31, 2012.

On January 29, 2014, the Partnership declared a cash distribution of $0.58 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. The $41.8 million distribution, including $2.9 million and $4.4 million to the general partner and preferred limited partners, respectively, was paid on February 14, 2014 to unitholders of record at the close of business on February 10, 2014.

NOTE 15 — 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, 2013, the Partnership had

2,322,483 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 352,586 phantom units, restricted units and unit options available for grant.

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. 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 distribution equivalent rights ("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, 2013, 278,795 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at December 31, 2013 include DERs. During the years ended December 31, 2013 and 2012, the Partnership paid $1.9 million and $0.7 million, respectively, with respect to the 2012 LTIP's DERs. No amount was paid during the year ended December 31, 2011 with respect to DERs. These amounts were recorded as reductions of partners' capital 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,					
	2013		2012		2011	
	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	948,476	$ 24.76	—	$ —	—	$ —
Granted	145,813	21.87	949,476	24.76	—	—
Vested(1)	(215,981)	24.73	—	—	—	—
Forfeited	(38,500)	23.96	(1,000)	24.67	—	—
Outstanding, end of year(2)(3)	839,808	$ 24.31	948,476	$ 24.76	—	—
		$ 9,166		$ 7,630		$ —

Non-cash compensation expense recognized (in thousands)

(1) The intrinsic value of phantom unit awards vested during the year ended December 31, 2013 was $6.1 million. No phantom unit awards vested during the years ended December 31, 2012 and 2011.
(2) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2013 was $17.2 million.
(3) There was approximately $81,000 and $31,000 recognized as liabilities on the Partnership's consolidated balance sheet at December 31, 2013 and 2012, respectively, representing 16,084 and 3,476 units, respectively, due to the option of the participants to settle in cash instead of units. The respective weighted average grant date fair value for these units was $22.15 and $28.75 at December 31, 2013 and 2012, respectively.

At December 31, 2013, the Partnership had approximately $8.9 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards.

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 370,750 unit options outstanding under the 2012 LTIP at December 31, 2013 that will vest within the following twelve months. No cash was received from the exercise of options for the years ended December 31, 2013, 2012 and 2011.

The following table sets forth the 2012 LTIP unit option activity for the periods indicated:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of year	1,515,500	$ 24.68	—	$ —	—	$ —
Granted	5,000	21.56	1,517,500	24.68	—	—
Exercised [1]	—	—	—	—	—	—
Forfeited	(37,825)	24.80	(2,000)	24.67	—	—
Outstanding, end of year[2][3]	1,482,675	$ 24.66	1,515,500	$ 24.68	—	—
Options exercisable, end of year[4]	370,700	$ 24.67	—	$ —	—	—
Non-cash compensation expense recognized (in thousands)		$ 3,514		$ 3,198		$ —

(1) No options were exercised during the years ended December 31, 2013, 2012 and 2011.
(2) The weighted average remaining contractual life for outstanding options at December 31, 2013 was 8.4 years.
(3) 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, 2013 was 8.4 years. There were no intrinsic values for options exercisable at December 31, 2013, 2012 and 2011.

At December 31, 2013, the Partnership had approximately $2.8 million in unrecognized compensation expense related to unvested unit options outstanding under the 2012 LTIP based upon the fair value of the awards. 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 periods indicated:

	Years Ended December 31,		
	2013	2012	2011
Expected dividend yield	8.0 %	5.9 %	— %
Expected unit price volatility	35.5 %	47.0 %	— %
Risk-free interest rate	1.4 %	1.0 %	— %
Expected term (in years)	6.31	6.25	—
Fair value of unit options granted	$2.95	$6.10	$ —

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.

NOTE 16 – 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,		
	2013	2012	2011
Gas and oil production:			
Revenues	$266,783	$92,901	$66,979
Operating costs and expenses	(97,237)	(26,624)	(17,100)
Depreciation, depletion and amortization expense	(129,729)	(47,000)	(27,430)
Asset impairment	(38,014)	(9,507)	(6,995)
Segment income	$1,803	$9,770	$15,454
Well construction and completion:			
Revenues	$167,883	$131,496	$135,283
Operating costs and expenses	(145,985)	(114,079)	(115,630)
Segment income	$21,898	$17,417	$19,653
Other partnership management:[1]			
Revenues	$32,989	$43,232	$45,260
Operating costs and expenses	(27,527)	(28,771)	(29,580)
Depreciation, depletion and amortization expense	(7,034)	(5,582)	(3,439)
Segment income (loss)	$(1,572)	$8,879	$12,241
Reconciliation of segment income (loss) to net income (loss):			
Segment income (loss):			
Gas and oil production	$1,803	$9,770	$15,454
Well construction and completion	21,898	17,417	19,653
Other partnership management	(1,572)	8,879	12,241
Total segment income	22,129	36,066	47,348
General and administrative expenses[2]	(78,063)	(69,123)	(27,536)
Chevron transaction expense[2]	—	(7,670)	—
Interest expense[2]	(34,324)	(4,195)	—
Gain (loss) on asset sales and disposal[2]	(987)	(6,980)	87
Net income (loss)	$(91,245)	$(51,902)	$19,899
Capital expenditures:			
Gas and oil production	$224,037	$117,279	$38,362
Other partnership management	11,953	1,864	3,223
Corporate and other	27,547	8,083	5,739
Total capital expenditures	$263,537	$127,226	$47,324

	December 31,	
	2013	2012
Balance sheet		
Goodwill:		
Gas and oil production	$18,145	$18,145
Well construction and completion	6,389	6,389
Other partnership management	7,250	7,250
	$31,784	$31,784
Total assets:		
Gas and oil production	$2,170,712	$1,339,906
Well construction and completion	55,031	62,472
Other partnership management	56,493	47,097
Corporate and other	61,564	49,477
	$2,343,800	$1,498,952

(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, Chevron transaction expense and interest expense have not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

NOTE 17 — SUBSEQUENT EVENTS

Distribution. On February 24, 2014, the Partnership declared its initial monthly distribution of $0.1933 per common unit for the month of January 2014, which is payable on March 17, 2014 to holders of record as of March 7, 2014. In January 2014, the Partnership's board of directors had approved the modification of its distribution payment practice to a monthly distribution program.

GeoMet Acquisition. On February 13, 2014, the Partnership entered into a definitive asset purchase and sale agreement to acquire certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for approximately $107.0 million in cash with an effective date of January 1, 2014, subject to certain purchase price adjustments. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia. The closing of the acquisition is subject to certain closing conditions, including a vote by GeoMet's stockholders to approve the transaction.

Cash Distribution. On January 29, 2014, the Partnership declared a cash distribution of $0.58 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2013. The $41.8 million distribution, including $2.9 million and $4.4 million to the general partner and preferred limited partners, respectively, was paid on February 14, 2014 to unitholders of record at the close of business on February 10, 2014.

NOTE 18 — 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 accompanying 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, 2013 and 2012. 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 37 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 15 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 Chief Operating Officer and 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, 2013, 2012, and 2011 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, 2013, 2012, and 2011, 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)(1)	NGLs (Bbls)(1)
Balance, January 1, 2011	176,065,003	1,832,535	—
Extensions, discoveries and other additions(2)	9,966,952	8,217	—
Sales of reserves in-place	(990)	—	—
Purchase of reserves in-place	586,662	2,216	—
Transfers to limited partnerships	(6,042,432)	—	—
Revisions(3)	(11,436,615)	77,661	—
Production	(11,462,149)	(274,330)	—
Balance, December 31, 2011	157,676,431	1,646,299	—
Extensions, discoveries and other additions(2)	6,756,817	10,688	—
Sales of reserves in-place	—	—	—
Purchase of reserves in-place	462,504,519	7,485,998	16,212,356
Transfers to limited partnerships	—	—	—
Revisions(4)	(27,760,192)	(153,413)	206,091
Production	(25,403,318)	(120,736)	(356,550)
Balance, December 31, 2012	573,774,257	8,868,836	16,061,897
Extensions, discoveries and other additions(2)	90,098,219	8,255,531	8,197,272
Sales of reserves in-place	(2,755,155)	—	(4,625)
Purchase of reserves in-place	452,683,902	1,598	55,187
Transfers to limited partnerships	(2,485,210)	(239,910)	(258,381)
Revisions(5)	(88,488,497)	(1,412,359)	(3,826,744)
Production	(57,993,487)	(485,226)	(1,267,590)
Balance, December 31, 2013	964,834,029	14,988,470	18,957,016
Proved developed reserves at:			
January 1, 2011	137,393,017	1,832,535	—
December 31, 2011	138,403,225	1,638,083	—
December 31, 2012	338,655,324	3,400,447	7,884,778
December 31, 2013	727,926,951	3,458,907	7,676,389
Proved undeveloped reserves at:			
January 1, 2011	38,671,986	—	—
December 31, 2011	19,273,206	8,216	—
December 31, 2012	235,118,932	5,468,389	8,177,120
December 31, 2013	236,907,078	11,529,563	11,280,627

(1) Oil includes NGL information for the year ended December 31, 2011, which was less than 500 MBbls.
(2) Principally includes increases of proved reserves due to the addition of Marcellus wells.
(3)

Represents a downward revision of proved undeveloped reserves in the New Albany Shale due to the reduction of certain drilling plans related to the Partnership's shallow natural gas wells, as well as a downward revision and related impairment charge related to the Partnership's shallow natural gas wells in Colorado.

(4) Represents a downward revision and related impairment charge related to the Partnership's shallow natural gas wells in Michigan and Colorado due to declines in the average 1st day of the month price for the year ended December 31, 2012 as compared with the year ended December 31, 2011.

(5) Represents a downward revision primarily due to a reduction of the Partnership's five year drilling plans in the Barnett Shale and pricing scenario revisions.

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,	
	2013	2012
Natural gas and oil properties:		
Proved properties	$2,489,587	$1,468,886
Unproved properties	211,536	292,053
Support equipment	23,004	13,110
	2,724,127	1,774,049
Accumulated depreciation, depletion and amortization	(646,680)	(504,625)
Net capitalized costs	$2,077,447	$1,269,424

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,		
	2013	2012	2011
Revenues	$266,783	$92,901	$66,979
Production costs	(97,237)	(26,624)	(17,100)
Depreciation, depletion and amortization	(129,729)	(47,000)	(27,430)
Asset impairment[(1)]	(38,014)	(9,507)	(6,995)
	$1,803	$9,770	$15,454

(1) 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. During the year ended December 31, 2012, the Partnership recognized $9.5 million of impairment related to its shallow natural gas wells in the Antrim and Niobrara shales. During the year ended December 31, 2011, the Partnership recognized $7.0 million of impairment related to its shallow natural gas wells in the Niobrara Shale.

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,		
	2013	2012	2011
Property acquisition costs:			

Proved properties	$798,941	$528,684	$9,199
Unproved properties	895	213,638	323
Exploration costs[1]	1,053	1,026	1,156
Development costs	214,383	83,538	29,809
Total costs incurred in oil & gas producing activities	$1,015,272	$826,886	$40,487

(1) There were no exploratory wells drilled during the years ended December 31, 2013, 2012 and 2011.

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, 2013, 2012, and 2011, 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,		
	2013	2012	2011
Future cash inflows	$5,145,835	$2,930,514	$949,286
Future production costs	(2,347,592)	(1,185,084)	(425,493)
Future development costs	(746,725)	(441,423)	(27,266)
Future net cash flows	2,051,518	1,304,007	496,527
Less 10% annual discount for estimated timing of cash flows	(1,012,326)	(680,331)	(276,668)
Standardized measure of discounted future net cash flows	$1,039,192	$623,676	$219,859

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 and gas 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,		
	2013	2012	2011
Balance, beginning of year	$623,676	$219,859	$236,630
Increase (decrease) in discounted future net cash flows:			
Sales and transfers of oil and gas, net of related costs	(167,581)	(54,969)	(46,304)
Net changes in prices and production costs	85,191	(87)	(34)
Revisions of previous quantity estimates	(1,881)	(6,378)	757
Development costs incurred	27,245	575	1,842
Changes in future development costs	(21,579)	—	(3,591)
Transfers to limited partnerships	(53,392)	—	(8,022)
Extensions, discoveries, and improved recovery less related costs	143,338	64	14,923
Purchases of reserves in-place	473,058	510,467	736
Sales of reserves in-place	(2,053)	—	(1)
Accretion of discount	62,368	21,986	23,663
Estimated settlement of asset retirement obligations	(18,858)	(2,823)	(3,105)
Estimated proceeds on disposals of well equipment	17,052	3,806	3,363
Changes in production rates (timing) and other	(127,392)	(68,824)	(998)

Outstanding, end of year	$1,039,192	$623,676	$219,859

NOTE 19 — QUARTERLY RESULTS (Unaudited)

	Fourth Quarter[(1)]	Third Quarter[(1)]	Second Quarter[(1)]	First Quarter[(1)]
	(in thousands, except unit data)			
Year ended December 31, 2013:				
Revenues	$181,196	$91,085	$83,326	$112,048
Net loss attributable to common limited partners and the general partner's interests	$(44,395)	$(43,261)	$(8,247)	$(7,334)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	$(45,604)	$(44,073)	$(9,269)	$(7,635)
General partner's interest	1,209	812	1,022	301
Net loss attributable to common limited partners and the general partner's interests	$(44,395)	(43,261)	$(8,247)	$(7,334)
Net loss attributable to common unitholders per unit:				
Basic	$(0.77)	$(0.74)	$(0.20)	$(0.17)
Diluted	$(0.77)	$(0.74)	$(0.20)	$(0.17)

(1) For the first, second, third, and fourth quarters of the year ended December 31, 2013, approximately 998,000, 923,000, 835,000, and 900,000 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, 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 third and fourth quarters of the year ended December 31, 2013, potential common limited partner units issuable upon conversion of the Partnership's 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 fourth quarter of the year ended December 31, 2013, 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.

	Fourth Quarter[(1)]	Third Quarter[(1)]	Second Quarter[(1)]	First Quarter
	(in thousands, except unit data)			
Year ended December 31, 2012:				
Revenues	$84,740	$74,743	$37,045	$71,101
Net income (loss) attributable to owner's interest, common limited partners and the general partner	$(20,750)	$(11,300)	$(16,707)	$(6,208)
	—	—	—	(250)

Portion applicable to owner's interest (period prior to the transfer of assets on March 5, 2012)				
Net income (loss) attributable to common limited partners and the general partner's interests (period subsequent to the transfer of assets on March 5, 2012)	$(20,750)	$(11,300)	$(16,707)	$(6,458)
Allocation of net loss attributable to common limited partners and the general partner:				
Common limited partners' interest	$(20,484)	$(11,074)	$(16,373)	$(6,329)
General partner's interest	(266)	(226)	(334)	(129)
Net loss attributable to common limited partners and the general partner's interests	$(20,750)	$(11,300)	$(16,707)	$(6,458)
Net income (loss) attributable to common unitholders per unit:				
Basic	$(0.53)	$(0.32)	$(0.54)	$(0.24)
Diluted	$(0.53)	$(0.32)	$(0.54)	$(0.24)

(1) For the second, third, and fourth quarters of the year ended December 31, 2012, approximately 420,000, 898,000 and 945,000 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 third and fourth quarters of the year ended December 31, 2012, 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.

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 general partner's 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 general partner's 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, excluding assets acquired from EP Energy. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2013, our disclosure controls and procedures were effective at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting

The management of our general partner 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 general partner's 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 1992 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.

In conducting management's evaluation of the effectiveness of its internal control over financial reporting, management has excluded, due to the timing, size, and complexity, the operations of our newly acquired assets from

EP Energy, which were acquired in July 2013, from our December 31, 2013 Sarbanes-Oxley 404 review (see “Item 8. Financial Statements and Supplemental Data – Note 4”). In connection with this acquisition, we have entered into a transition service agreement with the previous owner. As a result, we did not begin to perform substantially all accounting control functions related to our EP Energy Acquisition until January 31, 2014. EP Energy constituted 31% of our total assets and 14% of our total revenues for the year ended December 31, 2013. We are continuing to integrate this system’s historical internal controls over financial reporting with our existing internal controls over financial reporting. This integration may lead to changes in our or the acquired system’s historical internal controls over financial reporting in future fiscal reporting periods. During the year ended December 31, 2012, we acquired certain assets from Titan and DTE which have been fully integrated into our existing internal control environment in 2013. Other than the previously mentioned items, there have been no changes in our internal control over financial reporting during the fourth quarter of 2013 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, 2013. 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, 2013, 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, 2013, based on criteria established in the 1992 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. Our audit of, and opinion on, the Partnership's internal control over financial reporting does not include the internal control over financial reporting of EP Energy, a wholly-owned subsidiary, whose financial statements reflect aggregate total assets and revenues constituting 31% and 14%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2013. As indicated in Management's Report, EP Energy was acquired during 2013. Management's assertion on the effectiveness of the Partnership's internal control over financial reporting excluded internal control over financial reporting of EP Energy.

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, 2013, based on criteria established in the 1992 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, 2013, and our report dated February 28, 2014, expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

February 28, 2014

ITEM 9B: OTHER INFORMATION

None.

PART III

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our general partner manages our activities. Unitholders do not directly or indirectly participate in our management or operation or have actual or apparent authority to enter into contracts on our behalf or to otherwise bind us. 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 any of 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 chair of our audit committee, Harvey Magarick. Correspondence to Mr. Magarick should be marked "Confidential" and sent to Mr. Magarick's attention, c/o Atlas Resource Partners, L.P., 1845 Walnut Street, 10th Floor, Philadelphia, Pennsylvania 19103.

Other than one non-independent board member serving on the environmental, health and safety committee, the independent board members comprise all of the members of the managing board's committees: the conflicts committee, the audit committee and the environmental, health and safety committee. The conflicts committee has the authority to review specific matters as to which the managing board believes there may be a conflict of interest to determine if the resolution of the conflict proposed by our general partner is fair and reasonable to us. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls. The environmental, health and safety committee monitors our policies and management systems in place with respect to environment, health and safety and related matters consistent with prudent exploration and production industry practices.

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 manage and operate our business. Some of the officers of our general partner may spend a substantial amount of time managing the business and affairs of Atlas Energy 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 apart from its general partner and incentive distributions. We reimburse our general partner and its affiliates, including Atlas Energy, 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 to the conduct of our business. Our 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 and Officers of Our General Partner

The following table sets forth information with respect to those persons who serve as the officers of and on the board of directors of, our general partner:

Name	Age	Position(s)
Edward E. Cohen	75	Chairman of the Board and Chief Executive Officer
Jonathan Z. Cohen	43	Vice Chairman of the Board
Matthew A. Jones	52	President and Director
DeAnn Craig	62	Director
Jeffrey C. Key	48	Director
Harvey G. Magarick	74	Director
Bruce Wolf	65	Director
Mark D. Schumacher	51	Chief Operating Officer
Sean P. McGrath	42	Chief Financial Officer
Daniel C. Herz	37	Senior Vice President of Corporate Development & Strategy
Freddie M. Kotek	58	Senior Vice President of Investment Partnership Division
Lisa Washington	46	Senior Vice President, Chief Legal Officer and Secretary
Dave Leopold	50	Senior Vice President of Operations
Jerry Dominey	60	Senior Vice President of Exploration and Chief Geologist
Brad O. Eubanks	56	Senior Vice President of Land
Roger R. Myers	56	Vice President of Completion Services
Jack Crook	54	Vice President of Environment, Health and Safety
Dana K. Greathouse	58	Vice President of Drilling
Daniel J. Kortum	64	Vice President of Energy Marketing
Joel S. Heiser	47	General Counsel and Assistant Secretary
Jeffrey M. Slotterback	31	Chief Accounting Officer

Edward E. Cohen has been the Chairman of the Board and Chief Executive Officer of our general partner since February 2012. 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. 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 has served on the executive committee of Atlas Energy's general partner since 2006. 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 the consummation of the Chevron Merger in February 2011 (the "Chevron Merger") and also served as its President from September 2000 to October 2009. Mr. Cohen has been the Executive Chair of the managing board of Atlas Pipeline Partners GP, LLC ("Atlas Pipeline GP"), since its formation in 1999. 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 the consummation of the Chevron Merger in February 2011. In addition, Mr. Cohen has been Chair of the Board of Directors of Resource America, Inc. (a publicly-traded specialized asset management company) 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 September 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 the Vice Chairman of the Board of our general partner since February 2012. Mr. Cohen has served as Executive Chairman of the Board of Atlas Energy's general partner since January 2012. 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 has served as chairman of the executive committee of Atlas Energy's general partner since 2006. Mr. Cohen was the Vice Chairman of the Board of Atlas Energy, Inc. from its incorporation in September 2000 until the consummation of the Chevron Merger in February 2011. Mr. Cohen has been the Executive Vice Chair of the managing board of Atlas Pipeline GP since its formation in 1999. 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 the consummation of the Chevron Merger in 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.

Matthew A. Jones has served as President and Director of our general partner since March 2012 and as Chief Operating Officer from March 2012 until October 2013. Mr. Jones has served as a Senior Vice President of Atlas Energy's general partner and President and Chief Operating Officer of the exploration and production division of Atlas Energy's general partner since February 2011. Mr. Jones was Chief Financial Officer of Atlas Energy, Inc. from March 2005 until February 2011 and Executive Vice President of Atlas Energy, Inc. from October 2009 until February 2011. Mr. Jones was Chief Financial Officer of Atlas Energy Resources, LLC and Atlas Energy Management, Inc. from June 2006 until February 2011. Mr. Jones served as Chief Financial Officer of Atlas Energy GP, LLC from January 2006 until September 2009 and served as a member of the Board of Directors of Atlas Energy GP, LLC from February 2006 to February 2011. Mr. Jones served as Chief Financial Officer of Atlas Pipeline Partners GP, LLC from March 2005 to September 2009. From 1996 to 2005, Mr. Jones worked in the Investment Banking Group at Friedman Billings Ramsey, concluding as Managing Director, and in its Energy Investment Banking Group from 1999 to 2005. Mr. Jones is a Chartered Financial Analyst. Mr. Jones brings extensive financial and operational knowledge to our company and to the board of directors of our general partner, derived from his long background of service to our predecessors.

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 is an Adjunct Professor in the Petroleum Engineering Department of the Colorado School of Mines since January 2009 and serves as 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. Previously, she served as 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 has been a director for Samson Oil & Gas Limited since July 2011 and is the chairperson of its audit committee as well as a member of its compensation committee. Dr. Craig serves as chair of our general partner's environmental, health and safety committee. Dr. Craig is a Registered Professional Engineer in the State of Colorado. Dr. Craig is a Past-President of the Society of Petroleum Engineers (SPE) and currently serves as the Treasurer for the Society of Petroleum Engineers' Foundation. She is also a Past-President of the American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME). 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 the Company resulting from her work as a consultant to the Company, 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.

Jeffrey C. Key has served as a director of our general partner since February 2012. 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. From March 2004 until September 2013, Mr. Key was Vice President, Corporate Development for Tekelec (a supplier of telecommunications equipment). From March 2002 to March 2004, Mr. Key was the Managing Partner of his own consulting firm, Key Technology Partners, LLC, which provided strategy development and planning services to communications and networking technology companies. 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 and a member of the audit committee of Atlas Energy from 2006 until February 2011. Mr. Key has extensive experience in finance, financial statement analysis, strategic planning and growth projects, complemented by investment experience. Mr. Key brings a strong finance and accounting background to the board of directors of our general partner, and, as a "financial expert," serves as the chair of the audit committee. His experience enables him to provide insight into the capital markets and corporate finance issues. In addition, Mr. Key's wealth of finance and planning experience are valuable in analyzing capital needs and evaluating capital alternatives.

Harvey G. Magarick has served as a director of our general partner since September 2013. Mr. Magarick has maintained his own consulting practice since June 2004. From 1997 to 2004, Mr. Magarick was a partner at BDO Seidman (a national accounting firm). Mr. Magarick is a member of the board of trustees of the HC Capital Trust (an investment fund) and has been the chair of its audit committee since 2004. Mr. Magarick brings a strong accounting background to our general partner's board and serves as the chair of the audit committee. Mr. Magarick served as an independent member of the board of Atlas Energy, L.P., as well as the chair of its audit committee, from January 2006 to September 2013. Having served as a partner at BDO Seidman and due to his experience as chair of an investment fund's audit committee for the past nine years as well as his experience as chair of Atlas Energy L.P.'s audit committee, Mr. Magarick has developed a wealth of financial knowledge with respect to the oversight of (i) the preparation of consolidated financial statements, (ii) internal audit functions and (iii) public accountants, skills which are critical to our company and particularly our audit committee. Mr. Magarick's accounting experience is critical to understanding the varied issues that face us. In addition, Mr. Magarick's wealth of finance and accounting experience enable him to provide guidance with respect to accounting matters and financing transactions.

Bruce Wolf has served as a director of our general partner since March 2012. Mr. Wolf has been President of Homard Holdings, LLC (a wine manufacturer and distributor) since September 2003. Mr. Wolf has been of counsel with Picadio, Sneath, Miller & Norton, P.C., Pittsburgh, PA, since May 2003. Additionally, since June 1999, Mr. Wolf served as an independent consultant in connection with energy and securities matters, conducting research and providing expert testimony and litigation support. Mr. Wolf's experience with our business began in the 1980's. Mr. Wolf was a Senior Vice President of Atlas America, Inc. from October 1998 to May 1999 and, before that, Secretary and General Counsel of Atlas Energy Group from 1980. Mr. Wolf is a seasoned energy company director, having served as an independent member of the board of Atlas Energy Resources, LLC from December 2006 until September 2009. Mr. Wolf also served on the board of Atlas Energy, Inc. from September 2009 until February 2011. Mr. Wolf serves as chair of our general partner's conflicts committee. Having served on boards of the Company's affiliates for numerous years and having worked for Atlas entities for 19 years, Mr. Wolf is very familiar with our business and the challenges and material risks we face. The Board benefits from Mr. Wolf's combined extensive knowledge of the energy industry coupled with his strong legal and financial knowledge.

Mark D. Schumacher has served as Chief Operating Officer of our general partner since October 2013 and served as Executive Vice President of our general partner 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.

Sean P. McGrath has served as Chief Financial Officer of our general partner since February 2012. Mr. McGrath has served as Chief Financial Officer of Atlas Energy's general partner since February 2011. Mr. McGrath was Chief Accounting Officer of Atlas Energy, Inc. and Chief Accounting Officer of Atlas Energy Resources, LLC from December 2008 until February 2011. Mr. McGrath served as Chief Accounting Officer of Atlas Energy GP, LLC from January 2006 until November 2009 and as Chief Accounting Officer of Atlas Pipeline Partners GP, LLC from May 2005 until November 2009. Mr. McGrath was Controller of Sunoco Logistics Partners L.P. (a publicly-traded partnership that transports, terminals and stores refined products and crude oil) from 2002 until 2005. Mr. McGrath is a Certified Public Accountant.

Daniel C. Herz has served as Senior Vice President of Corporate Development and Strategy of our general partner since March 2012. Mr. Herz has served as Senior Vice President of Corporate Development and Strategy of Atlas Energy's general partner since February 2011. Mr. Herz has been Senior Vice President of Corporate Development of Atlas Pipeline Partners GP, LLC since August 2007. 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. Prior to joining Atlas Energy, Inc. and Atlas Pipeline Partners GP, LLC, Mr. Herz was an investment banker with Banc of America Securities from 1999 to 2003.

Freddie M. Kotek has served as Senior Vice President of our general partner since March 2012. Mr. Kotek has served as Senior Vice President of the Investment Partnership Division of Atlas Energy's general partner since February 2011. 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 served as Senior Vice President of our general partner since October 2013 and as Chief Legal Officer and Secretary of our general partner since February 2012. Ms. Washington has served as Vice President, Chief Legal Officer and Secretary of Atlas Energy's general partner since February 2011. 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. 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.

Dave Leopold has served as Senior Vice President of Operations of our general partner since December 2013 and served as Regional Vice President of Operations from March 2013 to December 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.

Jerry Dominey has served as Senior Vice President of Exploration and Chief Geologist of our general partner since October 2013 and before that served as Vice President of Exploration and Chief Geologist of our general partner from March 2012 to October 2013. Mr. Dominey has served as Vice President of Exploration and Chief Geologist of Atlas Energy's general partner since September 2011. Prior to joining Atlas Energy GP, LLC, Mr. Dominey served in many roles during his 32 year career with Royal Dutch Shell, including serving as the Team Leader/Manager of Unconventional New Opportunities at Shell Exploration and Production Company and serving in its International New Business Development division. From 1999 to 2000, he worked as Geologic Advisor for PDO in Oman. From 1993 to 1999, he was Team Leader/Seismic Interpreter for Shell Angola E&P and Senior Geologist for Shell China. Mr. Dominey worked for Pecten International from 1988 to 1993 as Senior Geologist/Geophysicist. From 1979 to 1988, he worked as a Senior Geologist for Shell Western E&P and Shell Offshore, Inc.

Brad O. Eubanks has served as Senior Vice President of Land of our general partner since October 2013 and before that served as Vice President of Land of our general partner from March 2012 to October 2013. Mr. Eubanks has served as Vice President of Land of Atlas Energy's general partner since August 2011. Mr. Eubanks began his career with Shell Oil Company in 1970 as a Landman. From 1986 until 1998, he served as a District Land Manager for various regions of the country for Shell Oil. In 1998, he became Manager of Land and Acquisitions for Shell Louisiana Company. In 2001, he became Team Lead – Rockies for Shell Exploration & Production, Inc., and from December 2009 to July 2011, he served as Team Leader-Gulf of Mexico for Shell Offshore, Inc. Mr. Eubanks has served on the American Association of Professional Landmen's board of directors from 2001 to 2011 and is a Certified Professional Landman.

Roger R. Myers has served as Vice President of Completion Services of our general partner since March 2012. Mr. Myers has served as Vice President of Completion Services of Atlas Energy's general partner since July 2011. Mr. Myers was the Manager of Completions – Unconventional Resources for EXCO Resources (PA), LLC from April 2008 until March 2011. From June 1998 until March 2008, he worked as the Northeast Region Technical Manager for BJ Services Company, U.S.A. and from February 1992 until June 1998, he was the Vice President Engineering and R & D for Clearwater, Inc. He joined Halliburton Services in August 1979 and served as an EIT, Field Engineer, Senior Field Engineer, Ohio Technical Advisor until he served as an Assistant District Manager from July 1990 until December 1991.

Jack Crook has served as Vice President of Environment, Health and Safety of our general partner since March 2012. Mr. Crook served as Operations & Compliance Chief of the Pennsylvania Department of Environmental Protection from March 2008 to March 2012 and Water Supply Supervisor from September 2001 to March 2008. During his time with the Pennsylvania Department of Environmental Protection, he assisted in developing new laws to deal with both public drinking water well design as well as oil and gas construction standards for pads, erosion and sedimentation, and mechanical integrity testing. He is a Licensed Professional Geologist in the State of Pennsylvania. He also serves on the Board of Directors of the Pennsylvania Independent Oil & Gas Association and is an alternate member of the Board of Directors for the Marcellus Shale Coalition.

Dana K. Greathouse has served as Vice President of Drilling since March 2012. Before that, he held various positions at Whiting Petroleum Corporation from October 2003 until March 2012, including Western Regional Drilling Manager from June 2008 to March 2012 and Senior Drilling Engineer from August 2007 to June 2008. Prior to joining Whiting in 2002, he held staff and management positions with KN Energy, Inc. and Schlumberger Limited. He is a Registered Professional Engineer in the State of Colorado.

Daniel J. Kortum has served as Vice President of Energy Marketing since March 2012. Before that, Mr. Kortum served as Director of Commercial/Marketing of EXCO Resources from December 2010 to March 2012 and as Vice President Midstream & Marketing for their Appalachian assets from September 2008 to November 2010. Prior to that, he was employed by Dominion Transmission, Inc. from April 2001 until September 2008. Throughout his career, Mr. Kortum worked for the U.S. Department of Energy and Damson Oil Corporation in Houston, TX; EQT in Pittsburgh, PA in various capacities including General Counsel for their interstate pipeline, Equitrans, Vice President Operations for Equitable Gas Company, and Director of Environment, Health & Safety for all Equitable Resources' companies. While employed by Dominion, he was responsible for gathering and midstream activity in Pennsylvania and West Virginia.

Joel S. Heiser has served as General Counsel and Assistant Secretary of our general partner since March 2012. Mr. Heiser has served as the Associate General Counsel of Atlas Energy's general partner since September 2011. From June 1, 2010 until joining Atlas Energy GP, LLC, Mr. Heiser was the Vice President of Legal of EXCO Resources (PA), LLC, and was the Vice President, General Counsel and Assistant Secretary from December 2006 through May 2010 for EXCO Resources (PA), Inc. Mr. Heiser was Of Counsel at Bricker & Eckler LLP from January 2003 through December 2006, an Associate at Arter & Hadden LLP from July 1997 through December 2002 and an Associate at Climaco, Climaco, Seminatore, Lefkowitz & Garofoli LPA from January 1995 through July 1997.

Jeffrey M. Slotterback has served as Chief Accounting Officer of our general partner since March 2012. Mr. Slotterback has served as Chief Accounting Officer of Atlas Energy's general partner since March 2011. 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.

We have assembled a board of directors of our general partner 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 2013 our executive officers, directors of our general partner and persons who beneficially owned more than 10% of our common units complied with all applicable filing requirements except for Mr. Herz who inadvertently filed one Form 3 late and Dr. Craig and Messrs. Key, Magarick and Wolf who each inadvertently filed one Form 4 late relating to one equity grant.

Committees of the Board of Directors of our General Partner

The standing committees of the board of directors of our general partner are the audit committee, the conflicts committee and the environmental, health and safety committee. As discussed in Item 11 – Executive Compensation, neither we nor the board of directors of our general partner had a compensation committee for the year ended December 31, 2013. Compensation of Atlas Energy's senior executives who provide services to us is determined by Atlas Energy's compensation 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. All of the members of the audit committee meet the independence standards established by the NYSE and the Securities Exchange Act of 1934. 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. Key, Mr. Magarick and Mr. Wolf. Mr. Magarick is the chairman of the audit committee and the board of directors of our general partner has determined that Mr. Key is an "audit committee financial expert," as defined by SEC rules. Prior to Mr. Coniglio's resignation from our general partner's board of directors, he served on the audit committee.

Conflicts Committee. The conflicts committee reviews specific matters that the board of directors of our general partner believes may involve conflicts of interest. The conflicts committee determines if the conflict of interest has been resolved in accordance with our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe to us or our unitholders. Members of the conflicts committee must not be an officer or employee of our general partner or an officer, director or employee of any of our general partner's affiliates, must not own any ownership interest in us or our general partner other than our common units and other awards granted to such director under our equity compensation plans, and must meet the independence standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. The members of the conflicts committee are Mr. Key, Mr. Magarick and Mr. Wolf, and Mr. Wolf is the chairman of the committee.

Environmental, Health and Safety Committee. The environmental, 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 environmental, health and safety matters consistent with prudent exploration and production industry practices. The environmental, health and safety committee monitors and reviews compliance with applicable environmental, 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 environmental, health and safety committee are Dr. Craig and Mr. Wolf. Dr. Craig serves as chair of the committee.

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 the principal executive officer, principal financial officer and principal accounting officer of our general partner, as well as to persons performing services for us generally. We have also adopted partnership governance guidelines and charters for our audit committee and environmental, 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 our 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 Board's role in risk oversight recognizes the multifaceted nature of risk management. The Board has empowered several Board committees with aspects of risk oversight. We administer our risk oversight function through our audit committee which monitors material enterprise risks and our environmental, health and safety committee. 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. It meets with the members of the enterprise risk management committee as needed to discuss our risk management framework and related areas. The audit committee 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. Our 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. Our audit committee incorporates its risk oversight function into its regular reports to the board of directors of our general partner. The environmental, health and safety committee 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. Our environmental, health and safety committee reviews actions taken by management with respect to deficiencies identified or improvements recommended.

In addition to our audit committee and environmental, health and safety committee's 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 general partner's senior executives will 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 will 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

Atlas Energy’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. Atlas Energy believes that the focus on revenue growth and distributable cash flow in making incentive bonus awards and unit price performance in granting equity awards provides a check on excessive risk taking. In addition, Atlas Energy has adopted a clawback policy that allows it to recoup any excess incentive compensation paid to its NEOs if the financial results on which the awards were based are materially restated due to fraud, illegal or intentional misconduct or gross negligence of the executive officer. Our Code of Business Conduct and Ethics, which applies to all officers and directors, further seeks to mitigate the potential for inappropriate risk taking. We also prohibit hedging transactions involving our units so our officers and directors cannot insulate themselves from the effects of our unit price performance.

Atlas Energy's compensation committee, together with senior management, also reviews compensation programs and benefits plans affecting employees generally (in addition to those applicable to our executive officers), and Atlas Energy 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 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's compensation committee with regard to executive compensation programs.

ITEM 11: EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The purpose of this Compensation Discussion and Analysis is to explain the philosophy of Atlas Energy's Compensation Committee for determining the compensation program for the Chief Executive Officer, Chief Financial Officer and three other most highly compensated executive officers of our General Partner for 2013 (the "Named Executive Officers" or "NEOs") and to discuss why and how the 2013 compensation package for these executives was implemented. Following this discussion are tables that include compensation information for the NEOs. The NEOs for 2013 are as follows:

- Edward E. Cohen, Chief Executive Officer and Chairman
- Sean P. McGrath, Chief Financial Officer
- Jonathan Z. Cohen, Vice Chairman of the Board
- Matthew A. Jones, President
- Daniel C. Herz, Senior Vice President of Corporate Development and Strategy

We do not directly compensate our NEOs. Rather, Atlas Energy allocates 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. Because Atlas Energy employs our NEOs, its compensation committee (the "Compensation Committee" or "Committee"), comprised solely of Atlas Energy independent directors, is responsible for designing our compensation objectives and methodology, and evaluating the compensation to be paid to our NEOs.

Executive Summary

2013 Performance Overview

2013 was another successful year for our company. Highlights of company performance in 2013 include:

- In an industry that strives to maintain constant levels of reserves of hydrocarbons, a declining asset, our proved reserves increased by approximately 52%.
- We acquired over 600,000 net undeveloped acres of energy rights (an increase of almost 200%) and over 340,000 net developed acres (an increase of 95%). In addition, we added approximately 1,500 potential drilling locations, more than doubling the 1,200 sites held at the beginning of the year.
- Our natural gas production increased by 97%.

Objectives of Our Compensation Program

An understanding of our executive compensation program begins with Atlas Energy's program objectives.

- Aligning the interests of our executives and unitholders. We seek 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. We seek to implement a pay-for-performance philosophy by tying a significant portion of our executives' compensation to their achievement of financial goals that are linked to our business strategy and each executive's contributions towards the achievement of those goals.
- Offering competitive compensation. We seek to offer an executive compensation program that is competitive and that helps us attract, motivate and retain top performing executives.

We continue to believe that a significant portion of executive compensation should be variable and based on defined performance goals and/or unit price change (i.e., “at risk”). Our program meets this goal by delivering compensation in the form of equity and other performance-based awards.

The Compensation Committee believes our executive compensation program includes key features that align the interests of our NEOs with our long-term strategic direction.

Elements of Our Executive Compensation Program

The 2013 compensation program for our NEOs consisted of the following components:

Component	Type of pay	Purpose	Key characteristics
Base salary	Fixed	Provide fixed compensation for performance of core duties that contribute to our success. Not intended to compensate for extraordinary or for above average performance.	Fixed compensation that is reviewed annually and adjusted if and when appropriate.
Annual incentives	Performance-based	Motivate NEOs to achieve annual performance targets.	Variable performance-based cash and equity awards tied to pre-established performance goals.
Long-term incentives	Performance-based	Align compensation with changes in unit prices and unitholder return experience.	Time-vested phantom stock and option awards, including Atlas Energy equity-based awards.

2013 Compensation Determinations

In line with the performance we achieved as summarized above and in accordance with the Compensation Committee’s compensation philosophy, the Committee approved compensation for 2013 and salaries for 2014 for the NEOs as follows:

- Base salary;
- Annual incentives; and
- Long-term incentives.

Compensation Objectives

We believe that our compensation program must support our business strategy, be competitive, and provide both significant rewards for outstanding performance and clear financial consequences for underperformance. We also believe that a significant portion of the NEOs' compensation should be "at risk" in the form of annual and long-term incentive awards that are paid, if at all, based on individual and company accomplishments.

Governance of Executive Compensation

Compensation Committee

The Compensation Committee is responsible for designing our compensation objectives and methodology, and evaluating the compensation to be paid to our NEOs. The Compensation Committee is also responsible for administering our employee benefit plans, including incentive plans.

The Compensation Committee is comprised solely of independent directors of the Atlas Energy board.

Chief Executive Officer

Our Chief Executive Officer, who also serves as the Chief Executive Officer of Atlas Energy's general partner, makes recommendations to the Compensation Committee regarding the salary, bonus, and incentive compensation component of each of the other NEO's total compensation. Our Chief Executive Officer provides the Compensation Committee with key elements of Atlas Energy's, our company's and the other NEOs' performance during the year. Our Chief Executive Officer, at the Compensation Committee's request, may attend Committee meetings solely to provide insight into our company's and the other NEOs' performance, as well as the performance of other comparable companies in the same industry.

Independent Compensation Consultant

For 2013, the Compensation Committee engaged Mercer (US) Inc., an independent compensation consulting firm, to provide information and objective advice regarding executive compensation. All of the decisions with respect to our NEOs' compensation, however, are made by the Compensation Committee.

Mercer evaluated awards made to Atlas Energy's NEOs (which include all of our NEOs except for Mr. Herz) in 2012 against a peer group and Mercer's compensation survey data for the oil and gas industry. Mercer worked with Atlas Energy's senior management to develop a peer group in 2012 that reflected as close as possible, Atlas Energy's business mix, structure and size. The peer group is comprised of 14 oil and gas companies with the majority having revenues ranging from ½ to 2 times Atlas Energy's revenues, which are near the median.

A critical criterion in our Compensation Committee's selection of Mercer to provide executive and director compensation consulting services was the fact that Mercer does not provide any other services to Atlas Energy or its affiliated companies. In addition to reaffirming this on an annual basis, Atlas Energy also conducts a search of its accounts payable system to confirm that no Mercer affiliates are providing services outside of the compensation consulting services. As discussed in "Item 10: Directors, Executive Officers and Corporate Governance - Code of Business Conduct and Ethics, Partnership Governance Guidelines and Audit Committee Charter" and "Item 13: Certain Relationships and Related Transactions, and Director Independence" both Atlas Energy and we have a code of business conduct and ethics as well as a related party transaction policy which governs potential conflicts of interest. Our directors and officers are also required to complete questionnaires on a regular basis which allows us to review whether there are any potential conflicts as a result of personal or business relationships. There are no business or personal relationships between the consultants from Mercer who work with Atlas Energy and our directors and executive officers other than the compensation consulting described herein.

Timing of Compensation Decision Process

The Compensation Committee makes its determination on compensation amounts shortly after the close of Atlas Energy's and our fiscal year. In the case of base salaries, the Committee recommends the amounts to be paid for the new fiscal year. In the case of annual bonus and long-term incentive compensation, the Committee determines the amount of awards based on the most recently concluded fiscal year.

We and Atlas Energy typically pay cash awards and issue equity awards in February of each year, although the Compensation Committee has the discretion to recommend salary adjustments and the issuance of equity awards at other times during the fiscal year.

Elements of our Compensation Program

Base Salary

Base salary is intended to provide fixed compensation to the NEOs for their performance of core duties that contributed to our success. Base salaries are not intended to compensate individuals for their extraordinary performance or for above average company performance.

Annual Incentives

Annual incentives are intended to tie a significant portion of each of the NEO's compensation to our annual performance and/or that of our subsidiaries or divisions for which the officer is responsible. Generally, the higher the level of responsibility of the executive within our company, the greater is the incentive component of that executive's target total cash compensation. The Compensation Committee may recommend awards of performance-based bonuses and discretionary bonuses.

Performance-Based Bonuses

Atlas Energy has an Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, to award bonuses for achievement of predetermined performance objectives during a 12-month performance period, generally Atlas Energy's and our fiscal year. Awards under the Senior Executive Plan may be paid in cash or in a combination of cash and time-vesting equity of Atlas Energy. A portion of the cash amount awarded to our participating NEOs is allocated to us.

During 2013, the Compensation Committee approved 2013 bonus awards to be paid from a bonus pool. The bonus pool is equal to a maximum of 18.3% of Atlas Energy's distributable cash flow. One of two goals for 2013 had to be met before any bonuses would be paid:

- distributable cash flow at least 80% of the average distributable cash flow allocable to Atlas Energy for the past three years; and

- average production volumes at least 80% of the average production volumes (which for us means production volumes and for APL means gathered volumes) for the past three years.

The goals are set early in the year, but actual awards are ultimately determined by the Compensation Committee's year-end evaluation that also evaluates other factors as set forth below. While the Compensation Committee has the discretion to make awards even if one of the goals is not met, it does not anticipate doing so absent exceptionally rare circumstances justifying the payment of a bonus. In the event that distributable cash flow includes any capital transaction gains in excess of $50 million, then only 10% of that excess is included in the bonus pool. Distributable cash flow means the sum of (i) cash available for distribution by Atlas Energy, including the distributable cash flow of any of its subsidiaries (including our company), regardless of whether such cash is actually distributed, plus (ii) to the extent not otherwise included in distributable cash flow, any realized gain on the sale of securities, including securities of a subsidiary, less (iii) to the extent not otherwise included in distributable cash flow, any loss on the sale of securities, including securities of a subsidiary. A return of Atlas Energy's capital investment in a subsidiary was not intended to be included and, accordingly, if distributable cash flow included proceeds from the sale of all or substantially all of the assets of a subsidiary, the amount of such proceeds to be included in distributable cash flow would be reduced by Atlas Energy's basis in the subsidiary.

The maximum award, expressed as a percentage of Atlas Energy's estimated 2013 distributable cash flow, for each of our NEO participants was as follows: Mr. E. Cohen, 6.22%; Mr. J. Cohen, 5.49%; Mr. Jones, 2.93%; and Mr. McGrath, 1.46%. Mr. Herz did not participate in the Senior Executive Plan in 2013. Pursuant to the terms of the Senior Executive Plan, the Compensation Committee has discretion to recommend reductions, but not increases, in maximum awards under the Senior Executive Plan. In making its decisions, the Compensation Committee considers factors, including growth of reserves, growth in production, processing and intake of natural gas, total market and distribution return to Atlas Energy's unitholders, and health and safety performance.

Discretionary Bonuses

In exceptional circumstances, discretionary bonuses may be awarded to recognize individual and group performance without regard to limitations otherwise in effect.

Long-Term Incentives

We believe that our long-term success depends upon aligning our executives' and unitholders' interests. To support this objective, Atlas Energy provides our executives with various means to become significant equity holders, including awards under our 2012 Long-Term Incentive Plan, which we refer to as our Plan. The Compensation Committee administers our Plan. Our NEOs are also eligible to receive awards under Atlas Energy's 2006 Long-Term Incentive Plan (the "Atlas Energy 2006 Plan") and its 2010 Long-Term Incentive Plan (the "Atlas Energy 2010 Plan"), which we refer to as the Atlas Energy Plans. Under all of the plans, the Compensation Committee 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.

Additional Information Concerning Executive Compensation

Deferred Compensation

All of Atlas Energy'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. In July 2011, Atlas Energy established the Atlas Energy Executive Excess 401(k) Plan (the "Excess 401(k) Plan"), a non-qualified deferred compensation plan that is designed to permit individuals who exceed certain income thresholds and who may be subject to compensation and/or contribution limitations under its 401(k) plan to defer an additional portion of their compensation. The purpose of the Excess 401(k) Plan is to provide participants with an incentive for a long-term career with Atlas Energy by providing them with an appropriate level of replacement income upon retirement. Under the Excess 401(k) 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 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 does not pay above-market or preferential earnings on deferred compensation. Participation in the Excess 401(k) Plan is available pursuant to the terms of an individual's employment agreement or at the designation of the Compensation Committee. Currently, Messrs. E. Cohen and J. Cohen are the only participants in the Excess 401(k) Plan. For further details, please see the 2013 Non-Qualified Deferred Compensation table. A portion of both the deferred amounts and the matching contributions are allocated to us.

Post-Termination Compensation

Atlas Energy's and our NEOs received substantial cash amounts from Chevron in connection with the Chevron Merger, both as a result of the termination payments due under their employment agreements and their equity holdings. The Compensation Committee believed that the amounts thus realized left these NEOs without adequate financial incentives to continue employment with Atlas Energy, which the Committee did not believe was in Atlas Energy's interest as it moved forward with significant new operations. In order to encourage these executives to remain with Atlas Energy on a long-term basis, Atlas Energy entered into employment agreements with Messrs. E. Cohen, J. Cohen, Jones and Herz that, among other things, provide compensation upon termination of their employment by reason of death or disability, by Atlas Energy without cause or by each of them for good reason. See "—Employment Agreements and Potential Payments Upon Termination or Change of Control."

The Compensation Committee considered the following in entering into these agreements:

- "Double trigger" severance payments—Change in control severance benefits (base salary and bonus payments) to each NEO are paid pursuant to a "double-trigger," which means that to receive such benefits employment must terminate both: (1) as a result of a qualifying termination of employment, where his position with Atlas Energy changes substantially and is essentially an involuntary termination, and (2) after a change in control.

- Benefit multiple—The Compensation Committee determined the benefit multiple, that is, the cash severance amount based on each executive's salary and bonus, after consideration of comparable market practices provided to the Committee by Mercer.

No Hedging of Company Stock

All of our employees are prohibited from hedging their company stock.

No Tax Gross Ups

We do not provide tax reimbursements to our NEOs.

Perquisites

At the discretion of the Compensation Committee, we provide perquisites to our NEOs. In 2013, these benefits were limited to providing automobile allowances or automobile related expenses to Messrs. E. Cohen, Jones and Herz.

Determination of 2013 Compensation Amounts

Following its review of Mercer's analyses, in the fall of 2013, the Compensation Committee began to prepare for the executive compensation process by discussing the schedule for upcoming meetings and reviewing a proposed calendar. The Compensation Committee held meetings in October to review and discuss the compensation philosophy. In February 2014, the Compensation Committee met with Mercer, with our Chief Executive Officer in attendance, to evaluate Atlas Energy's and our company's performance and to approve annual payouts to NEOs as well as long-term incentive grants to senior employees.

Base Salary

In February 2014, the Compensation Committee determined that then current base salaries for Messrs. E. Cohen, J. Cohen, Jones and Herz were appropriate for 2014, but increased Mr. McGrath's 2014 base salary. The portion of the base salaries allocated to us are as follows: Mr. E. Cohen—$380,000; Mr. J. Cohen—$266,000; Mr. Jones—$320,000; Mr. McGrath—$157,500; and Mr. Herz—$102,577.

Annual Incentives

After the end of our 2013 fiscal year, the Compensation Committee considered incentive awards pursuant to the Senior Executive Plan based on the year's performance. In determining the actual amounts to be paid to the NEOs, the Compensation Committee considered both individual and company performance. Our Chief Executive Officer made recommendations of incentive award amounts based upon Atlas Energy's performance as well as the performance of its subsidiaries, including our company's; however, the Compensation Committee had the discretion to approve, reject, or modify the recommendations.

The Committee confirmed that Atlas Energy had achieved not one, but both, of the threshold performance standards permitting bonus payments under the Senior Executive Plan. The Committee recognized the continued strong performance and decided to make awards that were generally commensurate with overall awards that had been granted in 2011 and 2012, and therefore, did not grant awards at the maximum level for any of the NEOs.

At this time, in view of evolving corporate governance standards, the Committee decided to continue to move annual incentive compensation from a largely cash-based system to a substantially equity-based bonus system. To that end, the Committee determined to grant awards that were substantially in the form of equity, such that no cash component of the bonuses awarded to the NEOs exceeded 32% as compared to 2012 when the cash component averaged 63%. Because the Committee deemed these equity awards to be annual incentive awards made in lieu of cash, they determined that these phantom units vest ratably over the next two years. The amount of the cash portion of the awards that was allocated to us was as follows: Mr. E. Cohen—$456,000; Mr. J. Cohen—$456,000; Mr. Jones—$600,000; and Mr. McGrath—$270,000.

For 2013, the Compensation Committee did not award any discretionary bonuses.

The following tables set forth the compensation allocation to us for fiscal years 2013 and 2012 for our NEOs. As required by SEC guidance, the tables also disclose awards under the ATLS Plans.

SUMMARY COMPENSATION TABLE

Name and principal position	Year	Salary ($)	Bonus ($)	Unit awards ($)[1]	Option awards ($)[2]	Non-equity incentive plan compensation ($)	All other compensation ($)		Total ($)
Edward E. Cohen, Chief Executive Officer and	2013	380,000	—	1,799,988	—	456,000	1,027,426	(3)	3,663,414
Chairman	2012	672,115	—	3,700,500	2,135,000	2,062,500	784,697		9,354,812
	2013	157,500	—	499,973	—	270,000	159,851	(4)	1,087,324
Sean P. McGrath, Chief Financial Officer	2012	100,000	—	1,233,500	305,000	220,000	73,824		1,932,324
	2013	266,000	—	1,599,968	—	456,000	922,444	(5)	3,244,412
Jonathan Z. Cohen, Vice Chairman of the Board	2012	460,462	—	3,700,500	2,135,000	1,971,000	699,660		8,966,622
	2013	320,000	—	1,099,995	—	600,000	479,010	(6)	2,499,005
Matthew A. Jones, President	2012	286,770	—	2,467,000	1,372,500	1,320,000	252,151		5,698,421
Daniel C. Herz, Senior Vice President of Corporate Development and Strategy	2013	105,000	225,000	499,973		—	396,113	(7)	1,226,086
	2012	84,000	240,000	1,726,900	610,000	—	222,603		2,883,503

(1) For 2013, the amounts reflect the grant date fair value of the phantom units under the Atlas Energy Plans. For 2012, the amounts reflect the grant date fair value of the phantom units under our Plan and the Atlas Energy Plans 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 our units and Atlas Energy's units. See Item 8: Financial Statements and Supplementary Data—Note 15 for further discussion regarding assumptions made in fair value valuation.

(2) The amounts in this column reflect the grant date fair value of options awarded under our Plan and the Atlas Energy Plans calculated in accordance with FASB ASC Topic 718. See Item 8: Financial Statements and Supplementary Data—Note 15 for further discussion regarding assumptions made in fair value valuation.

(3)

Comprised of (i) payments on DERs of $272,250 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $564,100 with respect to the phantom units awarded under the Atlas Energy Plans, (iii) a matching contribution of $190,000 under the Excess 401(k) Plan; and (iv) tax, title and insurance premiums for Mr. E. Cohen's automobile.

(4) Comprised of (i) payments on DERs of $90,750 with respect to the phantom units awarded under our Plan and (ii) payments on DERs of $69,101 with respect to the phantom units awarded under the Atlas Energy Plans.

(5) Comprised of (i) payments on DERs of $272,250 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $474,048 with respect to the phantom units awarded under the Atlas Energy Plans, (iii) a matching contribution of $133,000 under the Excess 401(k) Plan; and (iv) $43,146 paid under the agreement relating to Lightfoot.

(6) Comprised of (i) payments on DERs of $181,500 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $289,982 with respect to the phantom units awarded under the Atlas Energy Plans; and (iii) an automobile allowance.

(7) Comprised of (i) payments on DERs of $127,050 with respect to the phantom units awarded under our Plan, (ii) payments on DERs of $266,183 with respect to the phantom units awarded under the Atlas Energy Plans; and (iii) an automobile allowance.

2013 Grants of Plan-Based Awards

	Estimated possible payments under non-equity incentive plan awards[1]				All other stock awards: Number of	Grant date fair value of unit
Name	Threshold ($)	Target ($)	Maximum ($)	Grant date	units[2]	awards ($)[3]
Edward E. Cohen	N/A	N/A	21,500,000	2/4/13	47,281	1,799,988
Sean P. McGrath	N/A	N/A	5,100,000	2/4/13	13,133	499,973
Jonathan Z. Cohen	N/A	N/A	19,000,000	2/4/13	42,027	1,599,968
Matthew A. Jones	N/A	N/A	7,600,000	2/4/13	28,894	1,099,995
Daniel C. Herz	N/A	N/A	N/A	2/4/13	13,133	499,973

(1) Represents performance-based bonuses under the Senior Executive Plan which may be paid in cash and/or equity. As discussed under "Compensation Discussion and Analysis—Elements of our Compensation Program—Annual Incentives—Performance-Based Bonuses," the Compensation Committee set performance goals based on Atlas Energy's distributable cash flow and established maximum awards, but not minimum or target amounts, for each eligible NEO.

(2) Represents phantom units granted under the Atlas Energy Plans.

(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 has employment agreements with 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 the following 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 Atlas Energy ceases to be a public company unless Atlas Energy becomes a subsidiary of a public company and,
- in the case of Mr. E. Cohen, becomes the chief executive officer of the public parent immediately following the applicable transaction;
- in the case of Mr. J. Cohen, becomes an executive officer of the public parent with responsibilities substantially equivalent to his previous position immediately following the applicable transaction;
- in the case of Messrs. Jones and Herz, the CEO or the Chairman of Atlas Energy's general partner's board is not Atlas Energy's CEO or the CEO of the acquiring entity;
- the executive is required to relocate to a location more than 35 miles from the executive's previous location;
- in the case of Mr. E. Cohen and Mr. J. Cohen, ceasing to be elected to Atlas Energy's board; or
- any material breach of the agreement.

“Cause” is defined in Mr. E. Cohen 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 disability), which failure is materially and demonstrably detrimental to Atlas Energy and has continued for 30 days after written notice signed by a majority of the independent directors of Atlas Energy’s general partner; or
- executive is determined, through arbitration, to have materially breached the restrictive covenants in the agreement.

“Cause” is defined in Messrs. Jones and Herz’s employment agreements as:

- the executive has committed any demonstrable and material fraud;
- illegal or gross misconduct that is willful and results in damage to Atlas Energy’s 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 disability) after written demand and a reasonable opportunity to cure; or
- failure to follow reasonable written instructions which are consistent with his duties.

Edward E. Cohen

Effective May 16, 2011, Atlas Energy entered into an employment agreement with Mr. Cohen to secure his service as President and 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. As discussed above under “Compensation Discussion and Analysis,” Atlas Energy allocates a portion of Mr. Cohen’s compensation cost to us based upon an estimate of the time spent by Mr. Cohen on our activities.

The agreement provides for an initial annual base salary of $700,000, which may be increased at the discretion of the board of directors of Atlas Energy’s general partner. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs and health and welfare plans and receive perquisites and reimbursement of business expenses, in each case as provided by Atlas Energy for senior level executives generally. Mr. Cohen participates in the Excess 401(k) Plan, under which he may elect to defer up to 10% of his total annual cash compensation, which Atlas Energy must match on a dollar-for-dollar basis up to 50% of his annual base salary. See “2013 Non-Qualified Deferred Compensation.” During the term of the agreement, Atlas Energy must maintain a term life insurance policy on Mr. Cohen’s life which provides a death benefit of $3 million, which can be assumed by Mr. Cohen upon a termination of employment.

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 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, vacation, business expenses and other benefits (“Accrued Obligations”), a pro-rata bonus for the year of termination, based on the actual bonus that would have been earned had the termination of employment not occurred, determined and paid consistent with past practice (the “Pro-Rata Bonus”).

- Atlas Energy may terminate Mr. Cohen’s employment if he has been 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, but Atlas Energy is required to pay his base salary until it acts to terminate his employment. Upon termination of employment due to disability, Mr. Cohen will receive the Accrued Obligations, all amounts payable under Atlas Energy’s long-term disability plans, three years’ continuation of group term life and health insurance benefits (or, alternatively, Atlas Energy may elect to pay executive cash in lieu of such coverage in an amount equal to three years’ healthcare coverage at COBRA rates and the premiums it 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 Atlas Energy without cause or by Mr. Cohen for good reason, Mr. Cohen will be entitled to either (i) if he does not execute and not revoke a release of claims against Atlas Energy, 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 Atlas Energy, (A) a lump-sum cash payment in an amount equal to three times his average compensation (which, assuming a termination date of December 31, 2013, is defined 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 2011 and 2012, (B) Continued Benefits for three years, (C) the Pro-Rata Bonus, and (D) Acceleration of Equity Vesting.

- Upon a termination by Atlas Energy for cause or by Mr. Cohen without good reason, he is entitled to receive payment of the Accrued Obligations.

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 will be reduced such that the total payments to the executive which are subject to Internal Revenue Code Section 280G are no greater than the Section 280G "safe harbor amount" if he would be in a better after-tax position as a result of such reduction.

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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, 2013:

Reason for termination	Lump sum severance payment		Benefits[1]	Accelerated vesting of unit awards and option awards[2]
Death	$3,420,000	(3)	$—	$ $39,913,421
Disability	2,280,000		21,898	39,913,421
Termination by Atlas Energy without cause or by Mr. Cohen for good reason	11,698,388	(4)	21,898	39,913,421

(1) Dental and medical benefits were calculated using 2013 COBRA rates.
(2) Represents the value of unexercisable option and unvested unit awards disclosed in the "Outstanding Equity Awards at Fiscal Year-End" table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2013. The payments relating to unit awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2013.
(3) Represents Mr. Cohen's bonus for 2013 plus life insurance policy proceeds.
(4) Represents (i) three times ((a) Mr. Cohen's base salary plus (b) the average of his bonuses for 2012 and 2011) plus (ii) his bonus for 2013. The value of unit awards is based on the fair market value of the underlying stock at the grant date. The value of options is based on Black-Scholes option pricing at grant date.

Jonathan Z. Cohen

Effective May 16, 2011, Atlas Energy entered into an employment agreement with Mr. Cohen to secure his service as Executive Chairman of the Board. 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. As discussed above under "Compensation Discussion and Analysis," Atlas Energy allocates a portion of Mr. Cohen's compensation cost to us based upon an estimate of the time spent by Mr. Cohen on our activities.

The agreement provides for an initial annual base salary of $500,000, which may be increased at the discretion of the board of directors of Atlas Energy's general partner. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs and health and welfare plans of Atlas Energy and receive perquisites and reimbursement of business expenses, in each case as provided by Atlas Energy for senior level executives generally. Mr. Cohen participates in the Excess 401(k) Plan, under which he may elect to defer up to 10% of his total annual cash compensation, which Atlas Energy must match on a dollar-for-dollar basis up to 50% of his annual base salary. See "2013 Non-Qualified Deferred Compensation." During the term of the agreement, Atlas Energy must maintain a term life insurance policy on Mr. Cohen's life which provides a death benefit of $2 million, which can be assumed by Mr. Cohen upon a termination of employment.

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 will be reduced such that the total payments to the executive which are subject to Internal Revenue Code Section 280G are no greater than the Section 280G “safe harbor amount” if 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, 2013:

Reason for termination	Lump sum severance payment		Benefits[1]	Accelerated vesting of unit awards and option awards[2]
Death	$2,850,000	(3)	$ —	$ 31,374,460
Disability	2,090,000		31,788	35,755,710
Termination by us without cause or by Mr. Cohen for good reason	10,738,876	(4)	31,788	35,755,710

(1) Dental and medical benefits were calculated using 2013 COBRA rates.
(2) Represents the value of unexercisable option and unvested unit awards disclosed in the "Outstanding Equity Awards at Fiscal Year-End" table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2013. The payments relating to unit awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2013.
(3) Includes the $2 million death benefit from the life insurance policy and payment of the 2013 bonus.
(4) Represents (i) three times ((a) Mr. Cohen's base salary plus (b) the average of his bonuses for 2012 and 2011) plus (ii) his bonus for 2013. The value of unit awards is based on the fair market value of the underlying stock at the grant date. The value of options is based on Black-Scholes option pricing at grant date.

Matthew A. Jones

In November 2011, Atlas Energy entered into an employment agreement with Matthew A. Jones. Under the agreement, Mr. Jones has the title of Senior Vice President and President of the Exploration and Production Division of Atlas Energy. The agreement has an effective date of November 4, 2011 and has an initial term of two years, which automatically renews daily after the first anniversary of the agreement for one year terms. As discussed above under "Compensation Discussion and Analysis," Atlas Energy allocates a portion of Mr. Jones's compensation cost to us based upon an estimate of the time spent by Mr. Jones on our activities.

The agreement provides for an initial annual base salary of $280,000. Mr. Jones is entitled to participate in any of Atlas Energy's short-term and long-term incentive programs and health and welfare plans and receive perquisites and reimbursement of business expenses, in each case as provided for our senior executives generally.

The agreement provides the following benefits in the event of a termination of employment:

.

Upon a termination by Atlas Energy for cause or by Mr. Jones 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 (together, the “Accrued Obligations”).

- Upon a termination of employment due to death or disability (defined as Mr. Jones being physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and the determination by Atlas Energy’s general partner’s board of directors, in good faith based upon medical evidence, that he is unable to perform his duties), all equity awards held by Mr. Jones accelerate and vest in full upon such termination (“Acceleration of Equity Vesting”), and Mr. Jones or his estate is entitled to receive in one cash payment, in addition to payment of all Accrued Obligations and any accrued but unpaid bonus earned for any year before the date of termination, a pro-rata amount in respect of the bonus granted to the executive for the fiscal year in which the termination occurs in an amount equal to the bonus earned by Mr. Jones for the prior fiscal year multiplied by a fraction, the numerator of which is the number of days in the fiscal year in which the termination occurs through the date of termination, and the denominator of which is the total number of days in such fiscal year (the “Pro-Rata Bonus”). In addition, his family is entitled to company-paid health insurance for the one-year period after his death.

- Upon a termination of employment by Atlas Energy without cause (which, for purposes of the “Acceleration of Equity Vesting” includes a non-renewal of the agreement) or by the executive for good reason, Mr. Jones will be entitled to either:

- if Mr. Jones does not timely execute (or revokes) a release of claims against Atlas Energy, payment in one cash payment of the Accrued Obligations, any accrued but unpaid bonus and the Pro-Rata Bonus; or

· in addition to payment in one cash payment of the Accrued Obligations, any accrued but unpaid bonus and the Pro-Rata Bonus, if Mr. Jones timely executes and does not revoke a release of claims against Atlas Energy:

a lump-sum cash severance payment in an amount equal to two times his average compensation (which is the sum of his then-current base salary and the average of the cash bonuses earned for the three calendar years preceding the year in which the termination occurs);

healthcare continuation at active employee rates for two years (or, where such coverage would have a negative tax effect to Atlas Energy's healthcare plan or Mr. Jones, Atlas Energy may elect to pay Mr. Jones 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. Jones will be reduced such that the total payments to the executive which are subject to Section 280G are no greater than the Section 280G "safe harbor amount" if Mr. Jones 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. Jones if a termination event had occurred as of December 31, 2013:

Reason for termination	Lump sum severance payment	Benefits(1)	Accelerated vesting of unit awards and option awards(2)
Death	$1,320,000	$ 14,986	$ 16,278,088
Disability	1,320,000	14,986	16,278,088
Termination by us without cause or by Mr. Jones for good reason	3,233,333 (3)	29,971	16,278,088

(1) Dental and medical benefits were calculated using 2013 active employee rates.
(2) Represents the value of unexercisable option and unvested unit awards disclosed in the "Outstanding Equity Awards at Fiscal Year-End" table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2013. The payments relating to unit awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2013.
(3) Calculated based on Mr. Jones's 2013 base salary and the applicable bonus.

Daniel C. Herz

In November 2011, Atlas Energy entered into an employment agreement with Daniel C. Herz. Under the agreement, Mr. Herz has the title of Senior Vice President – Corporate Development and Strategy. The agreement has an effective date of November 4, 2011 and has an initial term of two years, which automatically renews daily after the first anniversary of the agreement for one year terms. As discussed above under "Compensation Discussion and Analysis," Atlas Energy allocates a portion of Mr. Herz's compensation cost to us based upon an estimate of the time spent by Mr. Herz on our activities.

The agreement provides for an initial annual base salary of $280,000. Mr. Herz is entitled to participate in any of Atlas Energy's short-term and long-term incentive programs and health and welfare plans and receive perquisites and reimbursement of business expenses, in each case as provided by Atlas Energy for senior executives generally.

The agreement provides the following benefits in the event of a termination of employment:

- Upon a termination by Atlas Energy 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 (together, the "Accrued Obligations").

- Upon a termination of employment due to death or disability (defined as Mr. Herz being physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and the determination by Atlas Energy’s general partner’s board of directors, in good faith based upon medical evidence, that he is unable to perform his duties), all equity awards held by Mr. Herz accelerate and vest in full upon such termination (“Acceleration of Equity Vesting”), and Mr. Herz or his estate is entitled to receive in one cash payment, in addition to payment of all Accrued Obligations and any accrued but unpaid bonus earned for any year before the date of termination, a pro-rata amount in respect of the bonus granted to the executive for the fiscal year in which the termination occurs in an amount equal to the bonus earned by Mr. Herz for the prior fiscal year multiplied by a fraction, the numerator of which is the number of days in the fiscal year in which the termination occurs through the date of termination, and the denominator of which is the total number of days in such fiscal year (the “Pro-Rata Bonus”). In addition, his family is entitled to company-paid health insurance for the one-year period after his death.

- Upon a termination of employment by Atlas Energy without cause (which, for purposes of the “Acceleration of Equity Vesting” includes a non-renewal of the agreement) or by the executive for good reason, Mr. Herz will be entitled to either:

- if Mr. Herz does not timely execute (or revokes) a release of claims against Atlas Energy, payment in one cash payment of the Accrued Obligations, any accrued but unpaid bonus and the Pro-Rata Bonus; or

- in addition to payment in one cash payment of the Accrued Obligations, any accrued but unpaid bonus and the Pro-Rata Bonus, if Mr. Herz timely executes and does not revoke a release of claims against Atlas Energy:

- a lump-sum cash severance payment in an amount equal to two years of his average compensation (which is the sum of his then-current base salary and the average of the cash bonuses earned for the three calendar years preceding the year in which the termination occurs);

- healthcare continuation at active employee rates for two years (or, where such coverage would have a negative tax effect to Atlas Energy’s healthcare plan or Mr. Herz, Atlas Energy may 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 will be reduced such that the total payments to the executive which are subject to Section 280G are no greater than the Section 280G “safe harbor amount” if Mr. Herz 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, 2013.

Reason for termination	Lump sum severance payment	Benefits[1]	Accelerated vesting of stock awards and option awards[2]
Death	$360,000	$ 7,387	$15,078,885
Disability	360,000	7,387	15,078,885
Termination by Atlas Energy without cause or by Mr. Herz for good reason	795,154 (3)	14,774	10,351,000

(1) Dental and medical benefits were calculated using 2013 active employee rates.
(2) Represents the value of unexercisable option and unvested unit awards disclosed in the “Outstanding Equity Awards at Fiscal Year-End Table.” The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2013. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2013.
(3) Calculated based on Mr. Herz’s 2013 base salary plus applicable bonus.

Long-Term Incentive Plans

Our Plan

Our 2012 Long-Term Incentive Plan, which we refer to as our 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 2,900,000 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 a common unit issued that entitles a participant to receive it upon vesting of the restricted unit. Prior to or upon grant of an award of restricted units, the 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	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 specified in the applicable award agreement(s), following a change of control	
Independent directors	Change of Control (as defined in our Plan)	Unvested awards immediately vest in full

The Atlas Energy 2006 Plan

The Atlas Energy 2006 Plan provides equity incentive awards to officers, employees and board members and employees of its general partner and its affiliates, consultants and joint-venture partners who perform services for it. The Atlas Energy 2006 Plan is administered by the Atlas Energy Compensation Committee. The Committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 common limited partner units.

Partnership Phantom Units. A phantom unit entitles a participant to receive a common unit upon vesting of the phantom unit. Non-employee directors may receive an annual grant of phantom units having a fair market value of $125,000, which upon vesting entitles the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. The phantom units vest over four years. In tandem with phantom unit grants, the Committee may grant a DER. The Committee determines the vesting period for phantom units. Phantom units granted under the Atlas Energy 2006 Plan generally vest 25% on the third anniversary of the date of grant, with the remaining 75% vesting on the fourth anniversary of the date of grant, except non-employee director grants vest 25% per year.

Partnership 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 Committee on the date of grant of the option. The Committee determines the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Unit options granted generally will vest 25% on the third anniversary of the date of grant, with the remaining 75% vesting on the fourth anniversary of the date of grant.

Change of Control.

Individual	Triggering event	Acceleration
Eligible employees	Change of Control (as defined in the Atlas Energy Atlas Energy 2006 Plan), 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 grant agreement 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 2006 Plan)	Unvested awards immediately vest in full

The Atlas Energy 2010 Plan

The Atlas Energy 2010 Plan provides equity incentive awards to officers, employees and board members and employees of its general partner and its affiliates, consultants and joint-venture partners who perform services for it. The Atlas Energy 2010 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 5,300,000 common limited partner units.

Partnership Phantom Units. A phantom unit entitles a participant to receive a common unit upon vesting of the phantom unit. Non-employee directors may receive an annual grant of phantom units having a market value of $125,000, which, upon vesting, entitle the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. The phantom units generally vest over four years. In tandem with phantom unit grants, the Committee may grant a DER. The Committee determines the vesting period for phantom units.

Partnership 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 Committee on the date of grant of the option. The Committee determines the vesting and exercise period for unit options.

Partnership Restricted Units. A restricted unit is a common unit issued that entitles a participant to receive it 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 2010 Plan), 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 2010 Plan 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 2010 Plan)	Unvested awards immediately vest in full

2013 Outstanding Equity Awards at Fiscal Year-End Table

	Option awards				Unit awards	
Name	Exercisable	Unexercisable	Option exercise price ($)	Option expiration date	Number of units that have not vested(#)	Market value of units that have not vested($)
Edward E. Cohen	543,825 (1)	—	20.75	11/10/2016	—	—
	—	761,355 (2)	20.44	3/25/2021	326,295 (3)	15,286,921
	87,500 (4)	262,500 (5)	24.67	5/15/2022	112,500 (6)	2,304,000
					47,281 (7)	2,215,115
Sean P. McGrath	16,314 (1)	—	20.75	11/10/2016	—	—
	—	38,067 (8)	20.44	3/25/2021	32,629 (9)	1,528,669
	12,500 (4)	37,500 (10)	24.67	5/15/2022	37,500 (11)	768,000
					13,133 (12)	615,281
Jonathan Z. Cohen	217,530 (1)	—	20.75	11/10/2016	—	—
	—	543,825 (13)	20.44	3/25/2021	271,912 (14)	12,739,077
	87,500 (4)	262,500 (5)	24.67	5/15/2022	112,500 (6)	2,304,000
					42,027 (15)	1,968,965
Matthew A. Jones	108,765 (1)	—	20.75	11/10/2016	—	—
	—	217,530 (16)	20.44	3/25/2021	163,147 (17)	7,643,437
	56,250 (4)	168,750 (18)	24.67	5/15/2022	75,000 (19)	1,536,000
					28,894 (20)	1,353,684
Daniel C. Herz	32,629 (1)	—	20.75	11/10/2016	—	—
	—	217,530 (16)	20.44	3/25/2021	163,147 (17)	7,643,437
	25,000 (4)	75,000 (21)	24.67	5/15/2022	52,500 (22)	1,075,200
					13,133 (12)	615,281

(1) Represents options to purchase Atlas Energy units.
(2) Represents options to purchase Atlas Energy units, which vest as follows: 3/25/2014 -190,338 and 3/25/2015 - 571,017.
(3) Represents Atlas Energy phantom units, which vest as follows: 3/25/2014 - 81,573 and 3/25/2015 - 244,722.
(4) Represents options to purchase our units.
(5) Represents options to purchase our units, which vest as follows: 5/15/2014 - 87,500, 5/15/2015 - 87,500 and 5/15/2016 - 87,500.
(6) Represents our phantom units, which vest as follows: 5/15/2014 - 37,500, 5/15/2015 - 37,500 and 5/15/2016 - 37,500.
(7) Represents Atlas Energy phantom units, which vest as follows: 2/4/2014 - 15,760, 2/4/15 - 15,760 and 2/4/2016 - 15,761

(8) Represents options to purchase Atlas Energy units, which vest as follows: 3/25/2014 - 9,516 and 3/25/2015 - 28,551.

(9) Represents Atlas Energy phantom units, which vest as follows: 3/25/2014 - 8,157 and 3/25/2015 - 24,472.

(10) Represents options to purchase our common units, which vest as follows: 5/15/2014 - 12,500, 5/15/2015 - 12,500 and 5/15/2016 - 12,500.

(11) Represents our phantom units, which vest as follows: 5/15/2014 - 12,500, 5/15/2015 - 12,500 and 5/15/2016 - 12,500.

(12) Represents Atlas Energy phantom units, which vest as follows: 2/4/2014 - 4,377, 2/4/15 - 4,377 and 2/4/2016 - 4,379.

(13) Represents options to purchase Atlas Energy units, which vest as follows: 3/25/2014 - 135,956 and 3/25/2015 - 407,869.

(14) Represents Atlas Energy phantom units, which vest as follows: 3/25/2014 - 67,978 and 3/25/2015 - 203,934.

(15) Represents Atlas Energy phantom units, which vest as follows: 2/4/2014 - 14,009, 2/4/15 - 14,009 and 2/4/2016 - 14,009.

(16) Represents options to purchase Atlas Energy units, which vest as follows: 3/25/2014 - 54,382 and 3/25/2015 - 163,148.

(17) Represents Atlas Energy phantom units, which vest as follows: 3/25/2014 - 40,786 and 3/25/2015 - 122,361.

(18) Represents options to purchase our common units, which vest as follows: 5/15/2014 - 56,250, 5/15/2015 - 56,250 and 5/15/2016 - 56,250.

(19) Represents our phantom units, which vest as follows: 5/15/2014 - 25,000, 5/15/2015 - 25,000 and 5/15/2016 - 25,000.

(20) Represents Atlas Energy phantom units, which vest as follows: 2/4/2014 - 9,631, 2/4/15 - 9,631 and 2/4/2016 - 9,632.

(21) Represents options to purchase our common units, which vest as follows: 5/15/2014 - 25,000, 5/15/2015 - 25,000 and 5/15/2016 - 25,000.

(22) Represents our phantom units, which vest as follows: 5/15/2014 - 17,500, 5/15/2015 - 17,500 and 5/15/2016 - 17,500.

2013 Non-Qualified Deferred Compensation

Name	Executive contributions in the last FY($)		Registrant contributions in the last FY($)		Aggregate earnings in the last FY($)	Aggregate balance at last FYE($)
Edward E. Cohen	190,000	(1)	190,000	(3)	20,260	400,260
Jonathan Z. Cohen	133,000	(2)	133,000	(4)	14,275	280,275

(1) This amount is included within the Summary Compensation Table for 2013 reflecting $38,000 in the salary column, $152,000 in the non-equity incentive compensation column.
(2) This amount is included within the Summary Compensation Table for 2013 reflecting $26,600 in the salary column and $106,400 in the non-equity incentive compensation column.
(3) This amount is included within the Summary Compensation Table for 2013 reflecting our $190,000 matching contribution in the all other compensation column.
(4) This amount is included within the Summary Compensation Table for 2013 reflecting our $133,000 matching contribution 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. 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 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 it 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'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.

2013 Director Compensation Table

Name	Fees earned or paid in cash($)	Stock awards($)		All other compensation($)[1]	Total($)
Anthony Coniglio	36,549	24,995	(2)	2,188	63,733
DeAnn Craig	58,750	74,991	(3)	4,510	138,251
Jeffrey C. Key	64,715	74,991	(3)	4,510	144,215
Harvey G. Magarick	23,736	74,995	(4)	2,043	100,775
Bruce Wolf	58,750	74,991	(3)	4,510	138,251

(1) Represents payments on DERs for our phantom units.

(2) For Mr. Coniglio, who resigned from our general partner's board of directors effective September 24, 2013, represents 1,035 of the phantom units which had a grant date fair value of $24.15.

(3) For Messrs. Key and Wolf and Dr. Craig, represents 3,493 phantom units granted under our Plan. 1,035 of the phantom units had a grant date fair value of $24.15 and 2,458 of the phantom units had a grant date fair value of $20.34. The 1,035 phantom units vest 25% on the anniversary of the date of grant as follows: 4/3/14—258, 4/3/15—258, 4/3/16—258 and 4/3/17—261. The 2,458 phantom units vest 25% of the anniversary of the date of grant as follows: 10/24/14—614, 10/24/15—614, 10/24/16—614 and 10/24/17—616.

(4) For Mr. Magarick, who joined our general partner's board of directors effective September 24, 2013, represents 3,649 phantom units granted under our Plan. 1,191 of the phantom units had a grant date fair value of $20.99 and 2,458 of the phantom units had a grant date fair value of $20.34. The 1,191 phantom units vest 25% on the anniversary of the date of grant as follows: 9/24/14—297, 9/24/15—297, 9/24/16—297 and 9/24/17—300. The 2,458 phantom units vest 25% of the anniversary of the date of grant as follows: 10/24/14—614, 10/24/15—614, 10/24/16—614 and 10/24/17—616.

Director Compensation

The officers or employees of our general partner or of Atlas Energy or its 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 2013, the annual retainer for non-employee directors was comprised of $65,000 in cash, which was increased from $50,000 in October 2013 and an annual grant of phantom units with DERs under our Plan having a fair market value of $75,000, which was increased from $25,000 in October 2013. These units will vest ratably over four years beginning on the grant date. The chair of the audit committee receives an annual fee of $25,000, which was increased from $15,000 in October 2013 and the chairs of the conflicts committee and the environmental, health and safety committee each receive an annual fee of $5,000.

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 February 25, 2014, 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 the executive officers of our general partner serving during the 2013 fiscal year, and (d) all of the 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 or warrants are deemed to be outstanding for purposes of computing the percentage of the person or group holding such options or warrants 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]				
Edward E. Cohen	509,743	(2)	*	
Jonathan Z. Cohen	496,851	(3)	*	
Matthew A. Jones	84,523	(8)	*	
Harvey G. Magarick	287		*	
DeAnn Craig	1,141	(7)	*	
Jeffrey C. Key	692	(7)	*	
Bruce Wolf	11,177	(7)	*	
Non-director Executive Officers[1]				
Sean P. McGrath	20,069	(9)	*	
Daniel C. Herz	35,742	(10)	*	
Freddie M. Kotek	38,660	(4)	*	
Jeffrey M. Slotterback	4,030	(11)	*	
Dave Leopold	6,250	(12)	*	
Mark D. Schumacher	34,556	(13)		
Lisa Washington	4,975	(14)	*	
All executive officers, directors and nominees as a group (14 persons)	937,330		*	
Other owners of more than 5% of outstanding units				
Atlas Energy, L.P. [1]	20,962,485		35.25	%
Leon G. Cooperman	6,813,919	(5)	11.46	%
R/C Energy IV TGP [6]…	7,593,800		12.00	%

*Less than 1%

(1) The business address for each director and executive officer as well as for Atlas Energy, L.P. is Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, PA 15275-1011.

(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) 290,344 units held by a charitable foundation of which Mr. E. Cohen, his spouse and their children serve as co-trustees; (iv) 7,510 units held by a trust (of which Mr. E. Cohen is the settlor) for the benefit of his spouse; (v) 6,869 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) 87,500 common unit purchase options. Mr. E. Cohen disclaims beneficial ownership of the units described above in (i) through (vi) above. 297,213 of these units are also included in the common units referred to in footnote 3 below.

(3) Includes (i) 112,138 units jointly owned by Mr. J. Cohen and his spouse; (ii) 290,344 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) 87,500 common unit purchase options. Mr. J. Cohen disclaims beneficial ownership to the units described above in (ii) and (iii).

(4) Includes (i) 278 units held by spouse; (ii) 5,826 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) 17,500 common unit purchase options.

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(5) This information is based on a Form 4 filed with the SEC on February 20, 2014. The address for Mr. Cooperman is 810 Seventh Avenue, 33rd Floor, New York, NY 10019.
(6) 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 IV is 712 Fifth Avenue, 51st Floor, New York, NY 10019. R/C Energy IV is the record owner of 3,796,900 common units and 3,796,900 Class B convertible preferred units which are convertible into common units within 60 days.
(7) Includes 475 phantom units that will vest and convert into common units within 60 days.
(8) Includes 56,250 common unit purchase options.
(9) Includes 12,500 common unit purchase options.
(10) Includes 25,000 common unit purchase options.
(11) Includes 2,500 common unit purchase options.
(12) Includes 6,250 phantom units that will vest and convert into common units within 60 days.
(13) Includes 14,153 Class B convertible preferred units which are convertible into common units within 60 days.
(14) Includes 3,125 common unit purchase options.

Equity Compensation Plan Information

The following table contains information about our 2012 Plan as of December 31, 2012:

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	948,476	n/a	
Equity compensation plans approved by security holders – unit options	1,515,500	$ 24.68	
Equity compensation plans approved by security holders – Total	2,463,976		436,024

The following table contains information about Atlas Energy's 2006 Plan as of December 31, 2012:

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	50,759	n/a	
Equity compensation plans approved by security holders – unit options	929,939	$ 20.75	
Equity compensation plans approved by security holders – Total	980,698		977,839

The following table contains information about Atlas Energy's 2010 Plan as of December 31, 2012:

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	2,044,227	n/a	
Equity compensation plans approved by security holders – unit options	2,504,703	$ 20.51	
Equity compensation plans approved by security holders – Total	4,458,930		1,189,736

ITEM 13: CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The board of directors of our general partner has determined that Messrs. Key, Magarick and Wolf each satisfy the requirement for independence set out in Section 303A.02 of the rules of the New York Stock Exchange including those set forth in Rule 10A-3(b)(1) of the Securities Exchange Act, and meet the definition of an independent member set forth in our Partnership Governance Guidelines. In making these determinations, the board of directors reviewed information from each of these non-management board members concerning all their respective relationships with us and analyzed the materiality of those relationships.

Effective as of March 2012, our general partner adopted 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. With certain exceptions outlined below, 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 Conflicts Committee of our general partner. If approval in advance is not feasible, the related party transaction must be ratified by the Conflicts Committee. In approving a related party transaction the Conflicts Committee will take into account, in addition to such other factors as the Conflicts Committee deems appropriate, the extent of the related party's interest in the transaction and whether the transaction is no less favorable to us than terms generally available to an unaffiliated third party under similar circumstances.

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 the board of directors for approval, by the compensation committee; (ii) compensation paid to directors for serving on the board 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

Atlas Energy owns approximately 20.96 million of our outstanding common units and 3.75 million convertible preferred units, representing approximately 36.9% limited partner ownership interest in us. In addition, Atlas Energy owns all of the equity of our general partner, Atlas Resource Partners GP, LLC. Our general partner owns 975,708 class A units, representing a 2% general partner interest, and all of our incentive distribution rights. As the owner of our incentive distribution rights, our general partner will be entitled to receive increasing percentages, up to a maximum of 50%, of any cash distributed by us as it reaches certain target distribution levels in excess of $0.46 per common unit of us in any quarter.

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. Some of the non-independent directors of our general partner also serve as directors of Atlas Energy's general partner.

We do not currently directly employ any persons to manage or operate our business. These functions are provided by employees of Atlas Energy 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, including Atlas Energy, for expenses they incur in managing our operations and for an allocation of the compensation paid to the executive officers of its general partner, 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 Atlas Energy based on the number of its employees who devote substantially all of their time to activities on our behalf. We reimburse Atlas Energy 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 our general partner and its affiliates $5.0 million for the year ended December 31, 2013 for compensation and benefits related to their employees.

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 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 initial Class C preferred distribution was paid for the quarter ending September 30, 2013. 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.

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, Atlas Energy or any of their respective 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, Atlas Energy or any of their respective 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.

Relationship with Atlas Pipeline Partners

APL agreed to provide design, procurement and construction management services for us with respect to a pipeline located in Lycoming County, Pennsylvania. The total estimated price for the project was under $5.0 million and was approved by our General Partner's conflicts committee in accordance with our related party transaction policy. We reimbursed APL approximately $1.8 million as of December 31, 2013.

APL compresses and gathers gas for us on its gathering systems located in Tennessee. We entered into an agreement, in February 2008, for APL to provide these services, which extends for the life of our leases. For 2013, we paid APL approximately $0.3 in compression and gathering fees.

Relationship in connection with 2013 notes offering

C&Co/PrinceRidge LLC was one of the initial purchasers in our January 2013 issuance of $275.0 million of 7.75% senior unsecured notes due on January 15, 2021. In connection with the notes offering, C&Co/PrinceRidge acted as initial purchaser with respect to $2.75 million principal aggregate amount of notes, and received the customary initial purchaser discount. Daniel Cohen, the chairman and chief executive officer of C&Co/PrinceRidge, is the son of Mr. E. Cohen, the chairman of the board of directors and chief executive officer of our general partner, and the brother of Mr. J. Cohen, the vice chairman of the board of directors of our general partner.

ITEM 14: PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2013 and 2012, the accounting fees and services (in thousands) charged by Grant Thornton, LLP, our independent auditors, were as follows:

	Years Ended December 31,	
	2013	2012

Audit fees[(1)]	$1,332	$1,191
Audit-related fees[(2)]	210	143
Tax fees	146	—
All other fees	—	—
Total accounting fees and services	$1,688	$1,334

(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, 2013 and 2012 for professional services rendered by Grant Thornton LLP substantially related to the historical audit of recently acquired EP Energy in 2013 and DTE in 2012 as well as certain necessary audit related services in connection with the registration and/or private placement of our Drilling Partnerships.

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 2013 and 2012.

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	Purchase and Sale Agreement, dated as of June 9, 2013, by and among EP Energy E&P Company, L.P., EPE Nominee Corp. 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[14]
2.2	Assignment & Assumption Agreement, dated as of June 9, 2013, between Atlas Resource Partners, L.P. and Atlas Energy, L.P. [14]
2.3	Asset Purchase Agreement, dated as of February 13, 2014, by and among GeoMet, Inc., GeoMet Operating Company, Inc., GeoMet Gathering Company, LLC and ARP Mountaineer Production, LLC. The exhibits and schedules to the Asset Purchase Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted exhibits and schedules will be furnished to the U.S. Securities and Exchange Commission upon request[25]
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]
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]
3.3	Certificate of Formation of Atlas Resource Partners GP, LLC[2]
3.4	Second Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC[24]
4.1	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]

4.2	Indenture dated as of July 30, 2013, by and between Atlas Resource Escrow Corporation and Wells Fargo Bank, National Association[22]
4.3	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]
4.4	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]
4.5	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]
4.6	Warrant to Purchase Common Units[6]
10.1	Pennsylvania Operating Services Agreement dated as of February 17, 2011 between Chevron North America Exploration and Production (f/k/a Atlas Energy, Inc.), Atlas Energy, L.P. (f/k/a Atlas Pipeline Holdings, L.P.) and Atlas Resources, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission[5]

Exhibit No.	Description
10.2	Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.3	Amendment No. 1 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of January 6, 2011(5)
10.4	Amendment No. 2 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of February 2, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.5	Transaction Confirmation, Supply Contract No. 0001, under Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated February 17, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.6	Gas Gathering Agreement for Natural Gas on the Legacy Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.7	Gas Gathering Agreement for Natural Gas on the Expansion Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)

10.8(a)	Credit Agreement between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders(3)
10.8(b)	First Amendment to Credit Agreement, dated as of April 30, 2012, between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders(10)
10.8(c)	Second Amendment to Amended and Restated Credit Agreement dated as of July 26, 2012, between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders(12)
10.8(d)	Third Amendment to Amended and Restated Credit Agreement dated as of December 20, 2012(15)
10.8(e)	Fourth Amendment to Amended and Restated Credit Agreement dated as of January 11, 2013(16)
10.8(f)	Fifth Amendment to Amended and Restated Credit Facility dated as of May 30, 2013(1)

Exhibit No.	Description
10.9	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)
10.10(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)
10.10(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
10.11	2012 Long-Term Incentive Plan of Atlas Resource Partners, L.P. (4)
10.12	Form of Phantom Unit Grant Agreement under 2012 Long-Term Incentive Plan(8)
10.13	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan(8)
10.14	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan(8)
10.15	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011(5)
10.16	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011(5)
10.17	Employment Agreement between Atlas Energy, L.P. and Matthew A. Jones dated as of November 4, 2011(7)
10.18	Employment Agreement between Atlas Energy, L.P. and Daniel Herz dated as of November 4, 2011(23)
10.19	Common Unit Purchase Agreement, dated as of March 15, 2012, among Atlas Resource Partners, L.P. and the various purchasers party thereto(9)
10.20	Registration Rights Agreement, dated as of April 30, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein(10)

10.21	Registration Rights Agreement, dated as of July 25, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein(12)
10.22	Registration Rights Agreement, dated as of May 16, 2012, between Atlas Resource Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein(13)
10.23	Underwriting Agreement dated November 20, 2012, among Atlas Resource Partners, L.P., Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets, Inc., Deutsche Bank Securities Inc., J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and RBC Capital Markets, LLC, as representatives of the several underwriters(19)
10.24	Second Lien Credit Agreement, dated as of December 20, 2012, by and among Atlas Resource Partners, L.P, the lenders party thereto and Wells Fargo Energy Capital, Inc. as administrative agent for the lenders(15)
10.25	Purchase Agreement dated as of January 16, 2013, among Atlas Resource Partners, L.P., Atlas Resource Finance Corporation and the initial purchasers named therein(17)
10.26	Registration Rights Agreement, dated as of January 23, 2013 among Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation and the initial purchasers named therein (20)
10.27	Distribution Agreement dated as of May 10, 2013, between Atlas Resource Partners, L.P. and Deutsche Bank Securities Inc., as representative of the several agents(11)

Exhibit No.	Description
10.28	Class C Preferred Unit Purchase Agreement, dated as of June 9, 2013, between Atlas Resource Partners, L.P. and Atlas Energy, L.P. [14]
10.29	Underwriting Agreement, dated June 10, 2013, among Atlas Resource Partners, L.P. and the underwriters named therein[21]
10.30	Registration Rights Agreement 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 Deutsche Bank Securities, Inc., for itself and on behalf of the Initial Purchasers[22]
10.31	Registration Rights Agreement dated as of July 31, 2013, by and among Atlas Energy, L.P. and Atlas Resource Partners, L.P. [6]
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.
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	Summary Reserve Report of Wright & Company, Inc.
99.2	Voting Agreement, dated as of February 13, 2014, by and among ARP Mountaineer Production, LLC,

	Atlas Resource Partners, L.P. and each of the persons listed on Annex I thereto(25)
101.INS	XBRL Instance Document(26)
101.SCH	XBRL Schema Document(26)
101.CAL	XBRL Calculation Linkbase Document(26)
101.LAB	XBRL Label Linkbase Document(26)
101.PRE	XBRL Presentation Linkbase Document(26)
101.DEF	XBRL Definition Linkbase Document(26)

(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 May 1, 2012.
(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 Current Report on Form 8-K filed on June 10, 2013.
(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 February 18, 2014.
(26) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed".

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 Resource Partners GP, LLC, its General Partner

Date: February 28, 2014 By: /s/ EDWARD E. COHEN
Edward E. Cohen
Chairman of the Board and Chief Executive Officer of the General Partner

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 February 28, 2014.

/s/ EDWARD E. COHEN Edward E. Cohen	Chairman of the Board and Chief Executive Officer of the General Partner
/s/ JONATHAN Z. COHEN Jonathan Z. Cohen	Vice Chairman of the Board of the General Partner
/s/ MATTHEW A. JONES Matthew A. Jones	President and Director of the General Partner
/s/ SEAN P. MCGRATH Sean P. McGrath	Chief Financial Officer of the General Partner
/s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback	Chief Accounting Officer of the General Partner
/s/ DEANN CRAIG DeAnn Craig	Director of the General Partner
/s/ JEFFREY C. KEY Jeffrey C. Key	Director of the General Partner

/s/ HARVEY MAGARICK Harvey Magarick	Director of the General Partner
/s/ BRUCE WOLF Bruce Wolf	Director of the General Partner

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