Atlas Resource Partners, L.P.
Form 10-K
March 03, 2014

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

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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 $1/8^{th}$ (12.5%) and $1/6^{th}$ (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.