Atlas Resource Partners, L.P.
Form 10-K
March 01, 2013
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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, 2012

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	**45-3591625**
(State or other jurisdiction or incorporation or organization)	**(I.R.S. Employer Identification No.)**
Park Place Corporate Center One 1000 Commerce Drive, Suite 400 Pittsburgh, PA	**15275**
(Address of principal executive offices)	**Zip code**

Registrant s telephone number, including area code: 800-251-0171

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

Title of each class	Name of each exchange on which registered
Common Units representing Limited Partnership Interests	**New York Stock Exchange**

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

None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ 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	¨	Accelerated filer	x
Non-accelerated filer	¨	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).   Yes ¨   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, 2012, was approximately $292.4 million.

The number of outstanding limited partner units of the registrant on February 25, 2013 was 47,809,707.

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.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

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 an NGL 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.

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.

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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 well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Proved developed reserves. Reserves 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 that 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 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.

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Reservoir. A porous and permeable underground formation containing a natural accumulation of economically 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.

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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, may, 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;

the introduction of Pennsylvania impact fees and severance taxes;

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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, in which we co-invest, to finance a portion of our natural gas and oil 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 and oil exploitation and development and sponsorship of investment partnerships and 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 and oil properties. As of December 31, 2012, the date of our most recent reserve reports, our estimated proved reserves were 723.4 Bcfe, including the reserves net to our equity interest in our investment partnerships. Of our estimated proved reserves, approximately 56% were proved developed and approximately 79% were natural gas. For the year ended December 31, 2012, our average daily net production was approximately 77.2 MMcfe. Through December 31, 2012, 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 over 525 wells in the Barnett Shale and Marble Falls play and 569.3 Bcfe of total proved reserves with average daily production of 31.9 MMcfe for the year ended December 31, 2012;

- the Appalachia basin, including the Marcellus Shale and the Utica Shale. We have ownership interests in over 10,200 wells primarily in the Appalachian basin, including approximately 270 wells in the Marcellus Shale and 112.6 Bcfe of total proved reserves with average daily production of 35.6 MMcfe for the year ended December 31, 2012;

- the Mississippi Lime and Hunton plays in northwestern Oklahoma. We own 21.0 Bcfe of total proved reserves with average daily production of 1.9 MMcfe for the year ended December 31, 2012; and

- the Chattanooga Shale in northeastern Tennessee, the Niobrara Shale in northeastern Colorado, the New Albany Shale in southwestern Indiana, and the Antrim Shale in Michigan, in which we have an aggregate 20.5 Bcfe of total proved reserves with average daily production of 7.8 MMcfe for the year ended December 31, 2012.

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 Assets* 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, which was funded by $119.5 million through the private placement of 6.0 million of our common units and $67.5 million of borrowings under our revolving credit facility. The assets include 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 Assets* 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 3.8 million of our common units and approximately 3.8 million of our Class B convertible preferred units (which had an estimated collective value of $193.2 million based upon the closing price of our publicly-traded common units as of the acquisition closing date) and approximately $15.4 million in cash for closing adjustments. 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 approximately 335 potential undeveloped drilling locations on the Titan acreage.

- *DTE Fort Worth Basin Assets* 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 assets include 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 believe that there are further potential development opportunities through vertical down-spacing and horizontal drilling in the Marble Falls formation, in which it expects to commence drilling operations by early 2013. The assets acquired from DTE are in close proximity to our other assets in the Barnett Shale.

Equal Mississippi Lime Assets 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 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, including $1.3 million related to post-closing adjustments. Both transactions were financed through borrowings under our revolving credit facility. The transaction increased our position in the Mississippi Lime play to 19,800 net acres in Alfalfa, Grant and Garfield counties in Oklahoma.

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In addition to our acquisition strategy, we have targeted certain high-returning plays, including the Marcellus Shale in northeastern Pennsylvania and the Utica Shale in eastern Ohio, for organic leasing efforts and development. In the Marcellus Shale, we have leased acreage in Lycoming County in northeast Pennsylvania, a highly desirable and productive dry gas area, where we have completed three pad sites that will each accommodate multiple horizontal wells, of which eight wells are in various stages of drilling as of December 31, 2012. We also have prospective Utica Shale acreage in Harrison, Tuscarawas, and Stark counties, Ohio, highly desirable areas which have experienced escalated permitting and drilling activity, where we have five horizontal wells in Harrison County in various stages of drilling as of December 31, 2012. We currently have interests in approximately 2,500 wells in Ohio and operate three field offices, which we intend to use to manage future Utica Shale development.

With over 1,250 attractive drilling locations at current commodity prices on approximately 144,000 undeveloped acres that we are actively developing, we believe we have significant organic growth opportunities.

We were formed in October 2011 to own and operate substantially all of the Atlas Energy E&P Operations, which were transferred to us on March 5, 2012 by Atlas Energy, L.P. (NYSE: ATLS; ATLS), a publicly-traded master limited partnership which owns 100% of our general partner Class A units and incentive distribution rights and an approximate 43% limited partner ownership interest (20,962,485 limited partner units) in us.

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

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 Appalachian Basin, and are characterized by long-lived reserves, favorable pricing for our production and readily available transportation. Moreover, because our production in the Appalachian Basin is located near markets in the northeast United States, we believe we will generally receive a premium over quoted prices on the New York Mercantile Exchange (NYMEX) for the natural gas we produce.

We are one of the leading sponsors of tax-advantaged investment 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 investment partnerships in the country. We believe that our lengthy association with many of the broker-dealers that act as placement agents for our investment partnerships provide us with a competitive advantage over entities with similar operations. We also believe that our sponsorship of investment partnerships has allowed us to generate attractive returns on drilling, operating and production activities.

Fee-based revenues from our investment partnerships and our substantially hedged production provide protection from commodity price volatility. Our investment partnerships provide us with stable, fee-based revenues which diminish the influence of commodity price fluctuations on our cash flows. In addition, because our investment 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 investment partnerships accounted for approximately 37% of our segment margin for the year ended December 31, 2012. Additionally, our natural gas, crude oil and NGL production was hedged approximately 81% on an equivalent basis for the year ended December 31, 2012. As of December 31, 2012, we have approximately 109 Bcfe of hedge positions on our natural gas, crude oil and NGL production for 2013 through 2017.

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.

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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 the area. We have added geologists and engineers to our technical staff that 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.

Business Strategy

The key elements of our business strategy are:

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 investment 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, 2012, we raised over $1.2 billion from outside investors through our investment partnerships. We intend to continue to develop our inventory of proved undeveloped locations through both sponsorship of investment partnerships and direct well drilling to add value through reserve and production growth.

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

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.

Continue to maintain control of operations and costs. We believe it is important to be the operator of wells in which we or our investment 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 and oil production to maximize both volumes and wellhead price. We were the operator of the vast majority of the properties in which we or our investment partnerships had a working interest at December 31, 2012.

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 Events

Cash Distribution. On January 24, 2013, we declared a cash distribution of $0.48 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2012. The $23.6 million distribution, including $0.6 million and $1.8 million to the general partner and preferred limited partners, respectively, was paid on February 14, 2013 to unitholders of record at the close of business on February 6, 2013.

Senior Notes. On January 23, 2013, we issued $275.0 million of 7.75% senior unsecured notes due on January 15, 2021 (7.75% Senior Notes). We used the net proceeds of approximately $268.3 million, net of underwriting fees and other offering costs of $6.7 million, to repay all of the indebtedness and accrued interest outstanding under our term loan credit facility and a portion of that outstanding under our revolving credit facility. Under the terms of our revolving credit facility,

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the borrowing base was reduced by 15% of the 7.75% Senior Notes to $368.8 million. In connection with the retirement of our term loan credit facility and the reduction in our revolving credit facility borrowing base, we accelerated $2.2 million of amortization expense related to deferred financing costs in January 2013. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 18 months. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a make whole redemption price as defined in the indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. The indenture governing the 7.75% Senior Notes contains covenants, including limitations of our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets.

Recent Developments

DTE Acquisition. On December 20, 2012, we completed the acquisition of DTE Gas Resources, LLC from DTE for $257.4 million, subject to certain post-closing adjustments (the DTE Acquisition). The assets include 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 believe that there are further potential development opportunities through vertical down-spacing and horizontal drilling in the Marble Falls formation, in which we expect to commence drilling operations by early 2013. The assets acquired from DTE are in close proximity to our other assets in the Barnett Shale.

Amendment to our revolving credit facility and new term loan credit facility. Also on December 20, 2012, in connection with the completion of the DTE Acquisition, we entered into an amendment to our revolving credit facility and a new term loan credit facility.

The amendment to our revolving credit facility:

- increased the borrowing base from $310.0 million to $410.0 million;

- stated that borrowings under the revolving credit facility bear interest, at our election, are at either LIBOR plus an applicable margin between 2.00% and 3.25% per annum or the base rate (which is the higher of the bank s prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.25% per annum;

- revised the maturity date to be the earlier of March 22, 2016 or February 19, 2014 (the date that is 91 days before the May 19, 2014 maturity date of our term loan credit facility) if any portion of the term loan debt is outstanding on that date; and

- amended the financial covenants to require that our ratio of Total Funded Debt (as defined in the credit agreement) to four quarters of EBITDA (as defined in the credit agreement) not be greater than 4.25 to 1.0 as of the last day of fiscal quarters ending on or before June 30, 2013, 4.00 to 1.0 as of September 30, 2013 and December 31, 2013, and 3.75 to 1.0 as of the last day of fiscal quarters ending after that date.

Our $77.6 term loan credit facility matures May 19, 2014, and contains terms substantially similar to our revolving credit facility except:

- our obligations are secured by second lien mortgages on our oil and gas properties and security interest in substantially all of our assets, and guarantees by substantially all of our subsidiaries;

borrowings bear interest, at our option, at either the prime rate plus 6.5% or LIBOR plus 7.5%;

we will be required to prepay borrowings with 100% of the net proceeds of any senior notes offering and 33% of the net proceeds from any equity offering; and

requires us to maintain a ratio of Total Funded Debt to EBITDA 0.50 higher than that required under our revolving credit facility, a ratio of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.25 to 1.0 as of the last day of any fiscal quarter, and a minimum asset coverage ratio (as defined in the credit agreement) of at least 1.5 to 1.0.

We borrowed $179.8 million under our revolving credit facility and $77.6 million under our term loan facility to partially fund the DTE acquisition. We repaid the term loan credit facility in full with the proceeds from the sale of the 7.75% Senior Notes in January 2013 (see Subsequent Events).

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

Acquisition of Titan Operating, L.L.C. In July 2012, we completed the acquisition of Titan in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had an estimated collective value of $193.2 million, based upon the closing price of our publicly traded units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments. Through the acquisition of Titan, we acquired interests in approximately 52 proved developed natural gas wells in the Barnett Shale, located in the Bend Arch Fort Worth Basin in North Texas. The cash paid at closing was funded through borrowings under our credit facility. The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act).

Acquisition of Assets from Carrizo Oil & Gas, Inc. In April 2012, we acquired certain oil and natural gas assets from Carrizo for approximately $187.0 million in cash. The assets acquired include interests in approximately 200 producing natural gas wells from the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas, proved undeveloped acres also in the Barnett Shale and gathering pipelines and associated gathering facilities that service certain of the acquired wells. The purchase price was funded through borrowing under our credit facility and $119.5 million of net proceeds from the sale of 6.0 million of our common units at a negotiated purchase price per unit of $20.00, of which $5.0 million was purchased by certain of our executives. The common units were issued in a private transaction exempt from registration under Section 4(2) of the Securities Act.

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

Geographic and Geologic Overview

Appalachian Basin Overview. The Appalachian Basin includes the states of Kentucky, Maryland, New York, Ohio, Pennsylvania, 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 and other formations primarily in Pennsylvania and the Utica Shale and other formations primarily in Ohio.

The Marcellus Shale is a black, organic rich shale formation located at depths between 6,000 and 8,500 feet and ranges in thickness from 75 to 250 feet. As of December 31, 2012, we had an interest in approximately 270 Marcellus Shale wells, consisting of 229 vertical wells and 41 horizontal wells. As of December 31, 2012, we initiated drilling for eight Marcellus Shale horizontal wells in northeastern Pennsylvania, all of which we are drilling through our partnership management business, which are expected to be completed in 2013. As of December 31, 2012, we have approximately 3,000 Marcellus Shale undeveloped acres in Lycoming County, PA. Our future drilling activity in certain portions of the Appalachian Basin located in southwestern Pennsylvania, West Virginia and New York will be limited until February 17, 2014 by the terms of the non-competition agreements between certain of Atlas Energy s officers and directors and Chevron Corporation (NYSE: CVX; Chevron).

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The Utica/Point Pleasant Shale is an Ordovician-age shale which covers a large portion of Pennsylvania, New York and West Virginia and lies several thousand feet below the Devonian-age Marcellus and other organic shales. The richest and thickest concentration of organic material is present within the Point Pleasant member of the Lower Utica formation. The Point Pleasant Shale is therefore the primary objective section of this shale play. As the Utica/Point Pleasant Shale increases in present day depth from central to eastern Ohio, so does the corresponding oil/condensate rich gas/dry gas areas, respectively. In general, near the Ohio/Pennsylvania border, the Utica/Point Pleasant Shale is in the dry gas window. As of December 31, 2012, we have approximately 4,500 net undeveloped acres prospective for the Utica Shale in Harrison, Tuscarawas and Stark counties in Ohio, upon which we have five horizontal wells in various stages of drilling as of December 31, 2012. 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.

Because the Appalachian Basin is located near the leading energy-consuming regions of the mid-Atlantic and northeastern United States, Appalachian producers have historically sold their natural gas at a premium to the benchmark price for natural gas on the NYMEX. In addition, Appalachian natural gas production has the advantage of a high energy content, ranging from 1.00 to 1.11 dekatherms (Dth) per Mcf. The majority of our existing natural gas sales contracts yield upward adjustments from index based pricing for throughput with an energy content above 1.0 Dth per Mcf. This higher energy content resulted in realized premiums averaging 1.05% over normal pipeline quality natural gas for the year ended December 31, 2012.

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, 2012, we had an interest in approximately 418 Barnett Shale wells and approximately 116,500 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, 2012, we had an interest in approximately 109 Marble Falls wells. Approximately 75,000 acres of our 116,500 acres prospective for the Barnett Shale are also prospective for the Marble Falls.

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, 2012, we had an interest in approximately 35 Hunton wells. As of December 31, 2012, we initiated drilling for 11 Mississippi Lime horizontal wells, all of which we are drilling through our partnership management business, four of which have been completed as of December 31, 2012. As of December 31, 2012, we have approximately 19,800 undeveloped acres prospective for the Mississippi Lime.

Tennessee. The Chattanooga Shale is a Devonian-age shale found at a depth of approximately 3,500 feet. We have over 100,000 net undeveloped acres in the Chattanooga Shale in northeastern Tennessee. We operate approximately 457 wells in the region, 453 of which are funded through our investment partnerships and 38 of which are horizontal wells. We also own two gas processing plants in eastern Tennessee with combined capacity of approximately 35 MMcf per day, which capacity we believe can be increased.

New Albany Shale. The Devonian-age New Albany Shale is an organic rich source rock found at depths of 500 to 3,000 feet, with thicknesses ranging from 100 to 200 feet. We have a leasehold of over 100,000 net acres in the New Albany Shale in southwestern Indiana located is in the biogenic gas window. The natural fracture patterns in the New Albany Shale are vertically oriented, which lends itself to a horizontal drilling approach. As of December 31, 2012, we have an interest in 111 wells in the New Albany Shale, of which we operate 105.

Niobrara Shale. Within the Denver-Julesburg Basin, we have primarily focused on the Niobrara Shale, which extends from northeastern Colorado to southern Wyoming into western Nebraska. Our developmental drilling program is focused on the shallow, gas-rich Niobrara in eastern Colorado, western Nebraska, and Kansas. Although natural gas was discovered in the Niobrara Shale in 1919, drilling in the area did not become commercial until the use of fracturing technologies became prevalent in the 1970s and 1980s. Development continued through the 1990s, but drilling success rates in the region were enhanced by the more recent development of 3-D seismic technology. The Niobrara Shale is suitable for conventional drilling of shallow developmental natural gas wells, which are wells drilled in an area of proven reserves to the depth of a horizon known to be productive. The Niobrara Shale presents the potential for efficient drilling, completion and production operations, as well as relatively quick well turn-in-line timeframes and favorable topography.

We are a party to a farm-out agreement with Black Raven Energy covering 178,000 acres located in the Niobrara formation in eastern Colorado and western Nebraska, pursuant to which we pay a per well fee and production royalties to Black Raven. The acreage subject to our farm-out agreement encompasses the development of shallow Niobrara gas wells at about 2,700 feet in depth with site selection based on the identification of 3D seismic structures. We operate 191 wells in the region, all of which were funded through our investment partnerships.

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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 each investment partnership proportionate to the value of our coinvestment in it and the value of the acreage we contribute to it, typically 15% to 31% of the overall capitalization of a particular partnership. We also receive an incremental interest in each partnership, typically 5% to 10%, for which we do not make any additional capital contribution. Consequently, our equity interest in the reserves and production of each partnership is typically between 20% and 41%. The following table presents our total net natural gas, oil and natural gas liquids production volumes and production per day for the three year period ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
Production per day:[(1)(2)]			
Natural gas (Mcfd)	69,408	31,403	35,855
Oil (Bpd)	330	307	373
Natural gas liquids (Bpd)	974	444	499
Total (Mcfed)	77,232	35,912	41,090

(1) Mcfd represents thousand cubic feet per day; Mcfed represents thousand cubic feet equivalents per day; and Bpd represent 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 investment 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

We market the majority of our natural gas production to gas utility companies, gas marketers, local distribution companies, industrial or other end-users, and companies generating electricity. The sales price of natural gas produced is a function of the market in the area and typically tied to a regional index. The production area and pricing indexes are as follows: Appalachian Basin and Mississippi Lime, primarily the NYMEX spot market price; Barnett Shale and Marble Falls, primarily the Waha spot market price; New Albany Shale and Antrim Shale, primarily the Texas Gas Zone SL and Chicago Hub spot market prices; and Niobrara formation, primarily the Cheyenne Hub spot market price. NGLs are produced by our natural gas processing plants, which extract the NGLs from the natural gas production, enabling the remaining dry gas (low Btu content) to meet pipeline specifications for long-haul transport to end users. Our NGLs are generally priced using the Mont Belvieu (TX) regional processing hub.

Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas, which comprised 79% of our proved reserves on an energy equivalent basis at December 31, 2012. 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, 2012, 2011 and 2010, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Years Ended December 31,		
	2012	2011	2010
Production revenues (in thousands):			
Natural gas revenue	$ 70,151	$ 49,096	$ 75,630
Oil revenue	11,351	10,057	10,541
Natural gas liquids revenue	11,399	7,826	6,879

Total revenues	$ 92,901	$ 66,979	$ 93,050
Average sales price:			
Natural gas (per Mcf):			
Total realized price, after hedge[1]	$ 3.29	$ 4.98	$ 7.08
Total realized price, before hedge[1]	$ 2.60	$ 4.53	$ 4.60

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	Years Ended December 31,		
	2012	2011	2010
Oil (per Bbl):			
Total realized price, after hedge	$ 94.02	$ 89.70	$ 77.31
Total realized price, before hedge	$ 91.32	$ 89.07	$ 71.37
Natural gas liquids (per Bbl) total realized price:	$ 31.97	$ 48.26	$ 37.78
Production costs (per Mcfe):			
Lease operating expenses(2)	$ 0.82	$ 1.09	$ 1.27
Production taxes	0.12	0.10	0.04
Transportation and compression	0.24	0.43	0.65
Total	$ 1.19	$ 1.61	$ 1.96

(1) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships. Including the effect of this subordination, the average realized gas sales prices were $2.76 per Mcf ($2.08 per Mcf before the effects of financial hedging), $4.28 per Mcf ($3.83 per Mcf before the effects of financial hedging) and $5.78 per Mcf ($3.30 per Mcf before the effects of financial hedging) for the years ended December 31, 2012, 2011 and 2010, 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 investment partnerships. Including the effects of these costs, total lease operating expenses per Mcfe were $0.58 per Mcfe ($0.94 per Mcfe for total production costs), $0.77 per Mcfe ($1.33 per Mcfe for total production costs) and $0.86 per Mcfe ($1.56 per Mcfe for total production costs) for the years ended December 31, 2012, 2011 and 2010, respectively.

Partnership Management Business

We generally fund our drilling activities through sponsorship of tax-advantaged investment 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 investment 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 investment partnerships are a source of fee-based revenues, which are not directly dependent on commodity prices. We receive an interest in the investment partnerships proportionate to the amount of capital and the value of the leasehold acreage that we contribute, which interest is typically 15% to 31% of the overall capitalization in a particular partnership. We also receive an additional interest in each partnership, typically 5% to 10%, for operating the wells and managing the general partner for which we do not make any additional capital contribution. This brings our total interest in the partnerships in a range from 20% to 41%.

Over the last five years, we raised over $1.2 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
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
2008	438.4	146.3	584.7
Total	$ 1,210.1	$ 379.9	$ 1,590.0

(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 investment partnerships, we receive the following fees:

Well construction and completion. For each well that is drilled by an investment partnership, we receive a 15% to 18% mark-up on those costs incurred to drill and complete the well;

Administration and oversight. For each well drilled by an investment partnership, we receive a fixed fee between $15,000 and $400,000, depending on the type of well drilled. Additionally, the 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 partnership pays us a monthly per well operating fee, currently $100 to $2,000, 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 wells; and

Gathering. Each royalty owner, 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 investment 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 investment 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 investment partnerships that were formed after October 2008, approximately 85% of the subscription proceeds received have been used to pay 100% of the partnership s intangible drilling costs. For example, an investment of $10,000 generally permits the investor to deduct from taxable ordinary income approximately $8,500 in the year in which the investor invests. For our investment partnerships that were formed prior to October 2008, approximately 90% of the subscription proceeds received were used to pay 100% of the partnership s intangible drilling costs.

Within our investment 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% per year, over a specific period, typically the first five to seven 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 investment 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, 2012, 2011 and 2010.

	Years Ended December 31,		
	2012	**2011**	**2010**
Gross wells drilled	105	160	117
Our share of gross wells drilled(1)	42	31	34

(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 investment 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, 2012, we had the following ongoing drilling activities:

	Gross			Net		
	Spud	**Total Depth**	**Completed**	**Spud**	**Total Depth**	**Completed**
Marcellus Vertical						
Marcellus Horizontal	4	4		4	4	
Barnett Horizontal	1	6	9	1	6	7
Mississippi Lime Horizontal	4	3	1	4	3	1
Utica Horizontal	5			5		

Chattanooga Vertical				
Chattanooga Horizontal				
Niobrara Vertical	2	2	2	2
Ohio Vertical				

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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 for all natural gas, oil and other hydrocarbons produced from any well(s) drilled on the leased premises. In the Appalachian Basin, Colorado, and Michigan Basins, this amount, historically has typically been between 1/8th (12.5%) and 1/6th (16.66%) 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%, which leaves us with a net revenue interest of 80%. In Oklahoma (Mississippi Lime) and Texas (Barnett shale and Marble Falls), both states where we have recently acquired substantial acreage positions, royalties are commonly in the 15-20% range, resulting in net revenue interests to us in the 80-85% range.

Historically, in almost all of the areas we operate in the Appalachian Basin, Colorado, Indiana and Michigan, the surface owner is normally the mineral owner, and we were drilling vertical wells on drilling units that typically comprised 40-160 acres, allowing us to deal with a single, or very few owners/lessors. This simplifies the research and acquisition process required to identify the proper owners of the mineral and surface rights and reduces the per acre lease acquisition cost and the time required to successfully acquire the desired leases that comprised drilling units. In the Texas Barnett Shale, Oklahoma Mississippi Lime and Appalachian Basin Marcellus and Utica plays, we are generally drilling horizontal wells on much larger drilling units (sometimes approaching 1,000 acres), which nearly always means acquiring mineral and/or surface rights from multiple parties. In the case of urban drilling areas in the Barnett Shale, we have as many as 3,500 royalty owners within a single drilling unit. The much higher volume (than typical Appalachian vertical wells) horizontal wells in these areas justify the additional acquisition cost and time involved in securing the necessary rights and agreements needed for the larger drilling units.

Because the acquisition of hydrocarbon leases in highly desirable basins is a very 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 these leases, we may elect to farm-in lease rights and/or purchase 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 covers.

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 always 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 utility companies, gas marketers, local distribution companies and industrial or other end-users. The sales price of natural gas produced is a function of the market in the area and typically tied to a regional index. The production area and pricing indexes are as follows: Appalachian Basin and Mississippi Lime, primarily the NYMEX spot market price; Barnett Shale and Marble Falls, primarily the Waha spot market price; New Albany Shale and Antrim Shale, primarily the Texas Gas Zone SL and Chicago Hub spot market prices; and Niobrara formation, primarily the Cheyenne Hub spot market price.

We do not hold firm transportation obligations on any pipeline that requires payment of transportation fees regardless of natural gas production volumes. As is customary in certain of our other operating areas, we occasionally commit a predictable portion of monthly production to the purchaser in order to maintain a gathering agreement.

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. NGL s 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. The resulting dry natural gas is sold as described above and our NGLs are generally priced using the

Mont Belvieu (TX) regional processing hub. 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 volumetric 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, 2012, Chevron and Atmos Energy Marketing, LLC accounted for approximately 43% and 11% of our total natural gas, oil, and NGL production revenues, respectively, with no other single customer accounting for more than 10% for this period.

Investment partnerships. We generally have funded a portion of our drilling activities through sponsorship of tax-advantaged investment drilling partnerships. In addition to providing capital for our drilling activities, our investment 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. 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 an end user, 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.

In Appalachia, our two primary gathering agreements are with Laurel Mountain Midstream, LLC (Laurel Mountain). Under the gathering agreements, we dedicate our natural gas production in certain areas within the Appalachian Basin to Laurel Mountain for transportation to interstate pipeline systems, local distribution companies, and/or end users in the area, subject to certain exceptions. In return, Laurel Mountain is required to accept and transport our dedicated natural gas in the Appalachian Basin 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.

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 92%, with 8% being the SemGas fee for all services provided.

Barnett and Marble Falls production in Texas is gathered by a variety of gathering entities 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 company 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.

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, 2012 and 2011, 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.

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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 will expire on February 17, 2014. The agreement may continue from month to month thereafter, subject to the right of either party to cancel the agreement at any time following the expiration of the initial term.

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 through our investment 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 investment partnerships. As a result, competition for investment capital to fund investment partnerships is intense.

Markets

The availability of a ready market for natural gas, oil and NGLs 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, 2012, 2011 and 2010, 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 of the Appalachian region and Michigan/Indiana. 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 investment 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:

- 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;

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- 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, 2012, 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 2013, 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.

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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 s). 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 for 2012 no later than April 1, 2013. 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 is in the process of reviewing the comments to the Draft Diesel Guidance, and at present we are not aware of EPA s timeframe to respond to the comments it received from the public.

The U.S. Senate and House of Representatives considered legislative bills in the 111th and 112th Sessions of Congress that, if enacted, would repeal the SDWA permitting exemption for hydraulic fracturing activities. Titled the Fracturing Responsibility and Awareness of Chemicals Act (or Frac Act), the proposed legislative bills as proposed could potentially lead to significant oversight of hydraulic fracturing activities by federal and state agencies. These legislative bills, if re-introduced, or any similar legislation introduced in the 113th Session of Congress could potentially result in significant regulatory oversight if enacted into law, 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.

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, Michigan imposes a 5% severance tax on natural gas and a 6.6% severance tax on oil, Tennessee imposes a 3% severance tax on natural gas and oil production and Ohio imposes a severance tax of $0.025 per Mcf of natural gas and $0.10 per Bbl of oil, Indiana imposes a severance tax of $0.03 per Mcf on natural gas and $0.24 per Bbl of oil, Colorado imposes a severance tax up to 5% of the value of oil and gas severed from earth, in addition to other applicable taxes, while West Virginia imposes a 5% severance tax on oil and gas. 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 2012, the impact fee for qualifying unconventional horizontal wells spudded during 2012 was $45,000 per well, while the impact fee for unconventional vertical wells was reduced to twenty percent of the horizontal well fee. 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 a horizontal well and 10 years for a 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. 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. Texas imposes a severance tax of 7.5% on the market value of gas produced and saved and 4.6% on the market value of condensate and oil produced.

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, EPA is conducting a study that evaluates any potential impacts of hydraulic fracturing on drinking water and ground water. 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.

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 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 Atlas Energy manage and operate our business. Approximately 482 Atlas Energy 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 Atlas Energy and its affiliates other than us and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

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.

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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 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 and oil prices will have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas 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 and oil have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2012, the NYMEX Henry Hub natural gas index price ranged from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $109.77 per Bbl to a low of $77.69 per Bbl. Between January 1, 2013 and February 25, 2013, the NYMEX Henry Hub natural gas index price ranged from a high of $3.57 per MMBtu to a low of $3.11 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $97.94 per Bbl to a low of $92.84 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 investment partnerships, contracting for drilling equipment and securing trained personnel. Our competitors may be able to pay more for natural gas 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 project areas are located in active drilling areas in the Appalachian Basin, 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 investment 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.

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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 from us, or cease to purchase 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, 2012, Chevron and Atmos Energy Marketing, LLC accounted for approximately 43% and 11% of our total natural gas, crude oil and natural gas liquids production revenue, respectively, with no other single customer accounting for more than 10% for this period. To the extent these and other key customers reduce the amount of natural gas, crude oil and natural gas liquids they purchase from us, our revenues and cash available for distributions to unit holders 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 or plan to 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, 2012, leases covering approximately 49,786 of our 321,642 net undeveloped acres, or 15.5%, are scheduled to expire on or before December 31, 2013. An additional 10% are scheduled to expire in each of the years 2014 and 2015. 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;

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- 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 investment 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 investment 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 and oil has been volatile and unpredictable for many years. To limit exposure to changing natural gas and oil prices, we use financial hedges for our production which may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. 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.

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 promulgated 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 to be 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;

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- 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 and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management s attention from other business concerns and increased demand on existing personnel;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

The scope and cost of these risks may be materially greater than estimated at the time of the acquisition. 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 Atlas Energy 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 2012 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 2012 acquisitions are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting independent petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain; our proved reserves estimates may thus exceed actual acquired proved reserves. In connection with our assessments, we perform a review of the acquired properties that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of the properties included in the 2012 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 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 and gas 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 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.

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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 studies are finalized. The New York Department of Environmental Conservation (NYDEC) accepted comments on its revised proposal to amend state regulations to address high-volume hydraulic fracturing through January 11, 2013. Final Regulations have not yet been issued. In October 2012, NYDEC asked the New York Health Department to assess the health impacts of high volume hydraulic fracturing. The Health Department has not completed its assessment. NYDEC is not expected to take any final action or make any decision regarding hydraulic fracturing until after the health review is completed and NYDEC, through the environmental impact statement, is satisfied that hydraulic fracturing can be done safely in New York State.

- Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. In February 2012, legislation was passed in Pennsylvania requiring, among other things, disclosure of chemicals used in hydraulic fracturing. To implement the new legislative requirements, in August of 2012 the Pennsylvania Department of Environmental Protection issued proposed conceptual changes to its environmental regulations governing oil and gas operations. The conceptual changes would include requiring secondary containment for tanks associated with hydraulic fracturing and the submission of increased water withdrawal information necessary to secure required Water Management Plans.

- 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 2012, the West Virginia Department of Environmental Protection introduced a proposed legislative rule titled Rules Governing Horizontal Well Development, which imposes more stringent regulation of horizontal drilling. The proposed rule was developed 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. 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 in September 2012, the EPA is considering withdrawing the

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draft guidance and reissuing the policies contained therein as a proposed rulemaking. In addition, legislation that would provide for increased federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic fracturing process could be introduced in the future. 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. 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 early 2013, 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.

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. 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 has proposed to revise a list of sources exempt from air permitting requirements such that previously exempted types of sources associated with oil and gas exploration and production would be 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 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 required reporting by September 28, 2012 for 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 that water. If we are unable to dispose of the water we use or remove from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially 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 of a Water Management Plan before hydraulically fracturing an unconventional well. The requirements of these plans continue to be modified by state laws and Pennsylvania Department of Environmental Protection (PADEP) policies. 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, pursuant to an executive order by Governor Kasich, the Ohio Department of Natural Resources promulgated emergency amendments to the regulations governing disposal wells in Ohio. The emergency 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.

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In an effort to offset budget deficits and fund state programs, many states have imposed impact fees and/or severance taxes on the natural gas industry. In February 2012, Pennsylvania implemented an impact fee for unconventional wells drilled in the Commonwealth. An unconventional gas well is a well that is drilled into an unconventional formation, which would include the Marcellus shale. The impact fee, which changes from year to year, is computed using the prior year s trailing 12 month NYMEX natural gas price and is based upon a tiered pricing matrix. For example, based upon natural gas prices for 2012, the impact fee for qualifying unconventional horizontal wells spudded during 2012 was $45,000 per well and the impact fee for unconventional vertical wells was reduced to twenty percent of the horizontal well fee. The impact fee is due by April 1 of the year following the year that a horizontal unconventional well is spudded or a vertical unconventional well is put into production. The fee will continue for 15 years for a horizontal unconventional well and 10 years for a vertical unconventional well. We estimate that the impact fee for our wells including the wells in our Drilling Partnerships will be in excess of $2 million for the year ended December 31, 2012.

Ohio Governor John Kasich has proposed a severance tax on gas, oil and natural gas liquids produced from high-volume producing formations that are recovered through hydraulic fracturing. Under the proposed tax plan, oil and natural gas liquids recovered through hydraulic fracturing in the Utica and Marcellus shales would be taxed at 1.5% of annual gross sales in the first year and 4% per year for each year thereafter. Natural gas would be taxed yearly at 1% of gross sales. The proposed plan also levies a $25,000 up front impact fee for each well drilled in the state.

President Obama s Fiscal Year 2013 Budget Proposal also includes provisions with significant tax consequences. If enacted, U.S. tax laws would be amended to eliminate the immediate deduction for intangible drilling and development costs and to eliminate the deduction from income for domestic production activities relating to oil and natural-gas exploration and development.

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

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

- The federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;
- The federal Clean Water Act and comparable state laws and regulations that impose obligations related to spills, releases, streams, wetlands and discharges of pollutants into regulated bodies of water;
- RCRA and comparable state laws that impose requirements for the handling and disposal of waste, including produced waters, from our facilities;
- CERCLA and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal; and
- Wildlife protection laws and regulations such as the Migratory Bird Treaty Act that requires operators to cover reserve pits during the cleanup phase of the pit, if the pit is open more than 90 days.

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

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

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

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

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

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

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

We sponsor limited and general partnerships to finance certain of our development drilling activities. Accordingly, the amount of development activities that we will undertake depends in large part upon our ability to obtain investor subscriptions to invest in these partnerships. We raised $127.1 million in 2012 and before our separation from Atlas Energy, it raised $141.9 million in 2011 and $149.3 million in 2010. In the future, we may not be successful in raising funds through these investment partnerships at the same levels that it experienced, and we also may not be successful in increasing the amount of funds we raise. Our ability to raise funds through our investment partnerships depends in large part upon the perception of investors of their potential return on their investment and their tax benefits from investing in them, which perception is influenced significantly by our historical track record of generating returns and tax benefits to the investors in our existing partnerships.

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

Changes in tax laws may impair our ability to obtain capital funds through investment partnerships.

Under current federal tax laws, there are tax benefits to investing in investment partnerships, including deductions for intangible drilling costs and depletion deductions. However, both the Obama Administration s budget proposal for fiscal year 2013 and other recently introduced legislation include proposals that would, among other things, eliminate or reduce certain

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

Fee-based revenues may decline if we are unsuccessful in sponsoring new investment partnerships.

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

Our revenues may decrease if investors in our investment partnerships do not receive a minimum return.

We have agreed to subordinate a portion of our share of production revenues, net of corresponding production costs, to specified returns to the investor partners in the investment partnerships, typically 10% per year for the first five to seven years of distributions. Thus, our revenues from a particular partnership will decrease if we do not achieve the specified minimum return.

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

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

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

Our credit facility contains various restrictive covenants that limit our ability to, among other things:

- incur additional debt or liens or provide guarantees in respect of obligations of other persons;
- pay distributions or redeem or repurchase our securities;
- prepay, redeem or repurchase debt;
- make loans, investments and acquisitions;
- enter into hedging arrangements;
- sell assets;

enter into certain transactions with affiliates; and

consolidate or merge with or into, or sell substantially all of our assets to, another person.

In addition, our credit facility requires us to maintain specified financial ratios. Our ability to meet those financial ratios can be affected by events beyond our control, and we may be unable to meet those tests. A breach of any of these covenants could result in a default under our credit facility. Upon the occurrence of an event of default, the lenders under the credit facility could elect to declare all amounts outstanding immediately due and payable and terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged a significant portion of our assets as collateral under our credit facility. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facility and our other liabilities. Our borrowings under our credit facility are, and are expected to continue to be, at variable rates of interest and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same.

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

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

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

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

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

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

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

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

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

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

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

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

Risks Relating to the Ownership of Our Common Units

There is not a long market history for our common units and the market price of our common units may fluctuate widely.

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

- changes in securities analysts recommendations and their estimates of our financial performance;
- the public s reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of natural gas and oil companies and securities of publicly traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;

departures of key personnel;

commencement of or involvement in litigation;

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

variations in the amount of our quarterly cash distributions;

future issuances and sales of our units; and

changes in general conditions in the U.S. economy, financial markets or the natural gas and oil industry.

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

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

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

Atlas Energy owns approximately 20.96 million common units, representing an approximately 43% limited partner ownership interest in us. Atlas Energy is free to sell some or all of these common units at any time. In addition, we have agreed to register under the U.S. Securities Act of 1933, as amended, which we refer to as the Securities Act, any sale of common units held by Atlas Energy and its affiliates. These registration rights allow Atlas Energy, our general partner and their affiliates to request registration of their common units and to include any of those units in a registration of other securities by us. If Atlas Energy and its affiliates were to sell a substantial portion of their units, it could reduce the market price of our outstanding common units.

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

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

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

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

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

the level of our capital expenditures.

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

our ability to make working capital borrowings to pay distributions;

the cost of acquisitions, if any;

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

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

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

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

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

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

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

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

If we do not pay distributions on our common units in any fiscal quarter, our unitholders are not entitled to receive distributions for such prior periods in the future.

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

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

Our partnership agreement prohibits any person or group that owns 20% or more of our common units then outstanding, other than Atlas Energy, our general partner, their respective affiliates, their transferees and persons who acquire common units directly from us with the prior approval of our general partner, from voting on any matter.

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

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

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

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

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

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

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

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

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Unlike the holders of common stock in a corporation, our common unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Common unitholders do not elect our general partner or the members of its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by Atlas Energy, the owner of 100% of the equity of our general partner. The board of directors of Atlas Energy s general partner is elected by the unitholders of Atlas Energy. Furthermore, the vote of the holders of at least two-thirds of all outstanding common units is required to remove our general partner. As a result of these limitations on the ability of holders of our common units to influence the management of the company, the price at which the common units trade could be diminished.

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

Our general partner may transfer its general partner interest to a third party without the consent of our unitholders, either before March 13, 2022 in a merger or in a sale of all or substantially all of its assets, or after March 13, 2022 under any circumstances if such transfer is otherwise in compliance with our partnership agreement. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and thereby influence the decisions made by the board of directors and officers.

In addition, our general partner may transfer all or a portion of its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of the incentive distribution rights.

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

Our partnership agreement does not limit the number of additional units that we may issue at any time without the approval of our common unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional units or other equity interests of equal or senior rank will have the following effects:

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

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

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

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

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Under the New York Stock Exchange (NYSE) listing standards, a limited partnership is exempt from certain NYSE corporate governance requirements, including:

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

We utilize some of the foregoing exemptions from the corporate governance requirements of the NYSE listing standards. As a result, neither we or our general partner have a nominating/governance committee or a compensation committee, and our general partner does not have a majority of independent directors.

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

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

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

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

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

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

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

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

a court or government agency determined that we were conducting business in a state but had not complied with that particular state s partnership statute; or

your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes control of our business.

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

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

Tax Risks to Unitholders

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

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

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

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

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

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

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

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

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be

unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Risks Relating to Our Ongoing Relationship with Atlas Energy and its Affiliates

Atlas Energy owns common units representing an approximate 43% limited partner ownership interest and all of the equity of our general partner, which, in turn, owns class A units representing a 2% general partner interest. Therefore, Atlas Energy has effective control of us.

Atlas Energy owns approximately 20.96 million common units representing an approximate 43% limited partner ownership interest and all of the equity of our general partner, which, in turn, owns class A units representing a 2% general partner interest in us. Accordingly, Atlas Energy possesses a substantial vote on all matters submitted to a vote of our unitholders, and will elect the board of directors of our general partner. The board of directors of Atlas Energy s general partner is elected by the unitholders of Atlas Energy. As long as Atlas Energy owns our general partner, it will be able to control, subject to our partnership agreement and applicable law, all matters affecting us, including:

- any determination with respect to our business direction and policies, including the appointment and removal of officers;
- any determinations with respect to mergers, business combinations or disposition of assets;
- our financing;
- compensation and benefit programs and other human resources policy decisions;

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the payment of dividends on our units; and

determinations with respect to our tax returns.

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

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

neither our partnership agreement nor any other agreement requires Atlas Energy or any of its affiliates to pursue a business strategy that favors us or to refer any business opportunity to us;

our general partner is expressly allowed to take into account the interests of parties other than us, such as Atlas Energy, in resolving conflicts of interest;

our partnership agreement eliminates any fiduciary duties owed by our general partner to us, and restricts the remedies available to unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;

our general partner determines the amount and timing of our drilling programs and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership securities and reserves;

our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

our general partner determines the amount and timing of any capital expenditure and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. Our partnership agreement does not set a limit on the amount of maintenance capital expenditures that our general partner may estimate;

our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;

our general partner intends to limit its liability regarding our contractual and other obligations;

our general partner decides which costs incurred by it and its affiliates are reimbursable by us; and our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

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

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership interest in us. Affiliates of our general partner, however, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Atlas Energy and its affiliates may make investments and acquisitions that may include entities or assets that we would have been interested in acquiring. For example, Atlas Energy retained its rights of way in Ohio, which can be used to develop natural gas and oil assets for development and production purposes. Pursuant to the separation and distribution agreement, Atlas Energy has the right to have access to our gathering assets in Ohio for any natural gas and oil production on commercially prevailing market terms to be agreed between Atlas Energy and us. Although we have the right to use such rights of way retained by Atlas Energy, as well as to use our own gathering assets in Ohio, Atlas Energy could

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use these rights of way, together with the right to have access to our gathering assets, to compete with us in the Ohio area. In addition, members of management of Atlas Energy, some of whom may also participate in the management of our general partner, have substantial experience in the natural gas and oil business.

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

Our partnership agreement provides that:

- subject to any contractual provision to the contrary, Atlas Energy has no obligation to refrain from engaging in the same or similar business activities or lines of business we do, doing business with any of our customers or employing or otherwise engaging any of our officers or employees;

- neither Atlas Energy nor any of its officers or directors will be liable to us or to our unitholders for breach of any duty, including any fiduciary duty, by reason of any of these activities; and

- none of our general partner, its affiliates or any of their respective directors or officers is under any duty to present any corporate opportunity to us which may be a corporate opportunity for such person and us, and such person will not be liable to us or our unitholders for breach of any duty, including any fiduciary duty, by reason of the fact that such person pursues or acquires that corporate opportunity for itself, directs that corporate opportunity to another person or does not present that corporate opportunity to us.

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

Certain of our officers and directors are subject to non-competition agreements that may effectively restrict our ability to expand our business in the Marcellus Shale.

Edward Cohen, who serves as our Chief Executive Officer, Chairman of the Board of our general partner and Chief Executive Officer and President of Atlas Energy, and Jonathan Cohen, who serves as our Vice Chairman of the Board and Executive Chairman of the Board of Atlas Energy, are each parties to a non-competition and non-solicitation agreement with Chevron Corporation. These agreements restrict each such individual, until February 17, 2014, from engaging in any capacity (whether as officer, director, owner, partner, stockholder, investor, consultant, principal, agent, employee, coventurer or otherwise) in a business engaged in the exploration, development or production of hydrocarbons in certain designated counties within the States of Pennsylvania, West Virginia and New York, and from engaging in certain solicitation activities with respect to oil and gas leases, customers, suppliers and contractors of Atlas Energy, Inc., Atlas Energy s predecessor which we refer to as AEI. The restrictions are subject to certain limited exceptions, including exceptions permitting Jonathan Cohen and Edward Cohen in certain circumstances to engage in the businesses conducted by Atlas Energy (including with respect to the operation of the assets Atlas Energy acquired from AEI in February 2011) and Atlas Pipeline Partners, L.P.

Due to the roles of Jonathan Cohen and Edward Cohen at Atlas Energy and at our general partner, our ability to expand our business in the Marcellus Shale may be limited.

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

Certain of the directors and officers of our general partner, including our Chairman, Chief Executive Officer, Vice Chairman, President, Chief Financial Officer and Chief Accounting Officer, have positions with Atlas Energy or its general partner. In addition, such directors and officers may own Atlas Energy common units, options to purchase Atlas Energy common units or other Atlas Energy equity awards. The individual holdings of Atlas Energy common units, options to purchase common units of Atlas Energy or other equity awards may be significant for some of these persons compared to these persons total assets. Their position at Atlas Energy and the ownership of any Atlas Energy equity or equity awards creates, or may create the appearance of, conflicts of interest when these expected directors and officers are faced with decisions that could have different implications for Atlas Energy than the decisions have for us.

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ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

ITEM 2: PROPERTIES

Natural Gas and Oil Reserves

The following tables summarize information regarding our estimated proved natural gas and oil reserves as of December 31, 2012. Proved reserves are the estimated quantities of crude oil, natural gas, and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. The estimated reserves include reserves attributable to our direct ownership interests in oil and gas properties as well as the reserves attributable to our percentage interests in the oil and gas properties owned by investment partnerships in which we own partnership interests. All of the reserves are located in the United States. We base these estimated proved natural gas and oil reserves and future net revenues of natural gas and oil reserves upon reports prepared by Wright & Company, Inc., an independent third-party reserve engineer. We have adjusted these estimates to reflect the settlement of asset retirement obligations on gas and oil properties. A summary of the reserve report related to our estimated proved reserves at December 31, 2012 is included as Exhibit 99.1 to this report. In accordance with SEC guidelines, we make the standardized measure estimates of future net cash flows from proved reserves using natural gas and oil sales prices in effect as of the dates of the estimates which are held constant throughout the life of the properties. Our estimates of proved reserves are calculated on the basis of the unweighted adjusted average of the first-day-of-the-month prices for each month within the prior 12-month period, and are listed below as of the dates indicated:

	December 31,	
	2012	**2011**
Unadjusted(1)		
Natural gas (per Mcf)	$ 2.76	$ 4.12
Oil (per Bbl)	$ 94.71	$ 96.19
Natural gas liquids (per Bbl)	$ 56.83	$ 57.71
Adjusted(1) (2)		
Natural gas (per Mcf)	$ 2.53	$ 4.42
Oil (per Bbl)	$ 92.26	$ 91.04
Natural gas liquids (per Bbl)	$ 33.79	$ 63.76

(1) Mcf represents thousand cubic feet; and Bbl represents barrels.

(2) The adjusted weighted average natural gas price is the Base product price, with the representative price of natural gas adjusted for basis premium and the Btu content to arrive at the appropriate net price. The adjusted weighted average oil and natural gas liquid price is the Base product price, adjusted for local contracted gathering arrangements. Amounts shown do not include financial hedging transactions.

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

The preparation of our natural gas and oil reserve estimates was completed in accordance with our prescribed internal control procedures by our reserve engineers. For the periods presented, Wright and Company, Inc., was retained to prepare a report of proved reserves. The reserve information includes natural gas and oil reserves which are all located in the United States, primarily in Ohio, Oklahoma, Pennsylvania and Texas. The independent reserves engineer s evaluation was based on more than 36 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. Our internal control procedures include verification of input data delivered to our third-party reserve specialist, as well as a multi-functional management review. The preparation of reserve estimates was overseen by our Senior Reserve Engineer, who is a member of the Society of Petroleum Engineers and has more than 14 years of natural gas and oil industry experience. The reserve estimates were reviewed and approved by our senior engineering staff and management, with final approval by our Senior Vice President.

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

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

	Proved natural gas and oil reserves at December 31,	
	2012	**2011**
Proved reserves:		
Natural gas reserves (MMcf)(1):		
Proved developed reserves	338,655	138,403
Proved undeveloped reserves(2)	235,119	19,273
Total proved reserves of natural gas	573,774	157,676
Oil reserves (MBbl)(1):		
Proved developed reserves	3,400	1,638
Proved undeveloped reserves(2)	5,469	8
Total proved reserves of oil(3)	8,869	1,646
NGL reserves (MBbl):		
Proved developed reserves	7,885	
Proved undeveloped reserves(2)	8,177	
Total proved reserves of NGL(3)	16,062	
Total proved reserves (MMcfe)(1)	723,359	167,552
Standardized measure of discounted future cash flows (in thousands)(4)	$ 623,676	$ 219,859

(1) MMcf represents million cubic feet; MMcfe represents million cubic feet equivalents; and MBbl represents thousand barrels.
(2) Our ownership in these reserves is subject to reduction as we generally makes capital contributions, which includes leasehold acreage associated with our proved undeveloped reserves, to our investment partnerships in exchange for an equity interest in these partnerships, which historically ranges from 20% to 41%, which effectively will reduce our ownership interest in these reserves from 100% to our respective ownership interest as we make these contributions.
(3) Includes less than 500 MBbl of natural gas liquids proved reserves at December 31, 2011.
(4) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest and income tax expenses, or to depletion, depreciation and amortization. The future cash flows are discounted using an annual discount rate of 10%. Standardized measure does not give effect to commodity derivative contracts. Because we are a limited partnership, no provision for federal or state income taxes has been included in the December 31, 2012 and 2011 calculations of standardized measure, which is, therefore, the same as the PV-10 value.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

Proved Undeveloped Reserves (PUDS)

PUD Locations. As of December 31, 2012, we had 328 PUD locations totaling approximately 317.0 Bcfe s of natural gas, oil and NGLs. These PUDS are based on the definition of PUD s in accordance with the SEC s rules allowing the use of techniques that have been proven effective through documented evidence, such as actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty.

Historically, the primary focus of our drilling operations has been in the Appalachian Basin. Subsequent to our acquisitions in the Barnett Shale/Marble Falls and Mississippi Lime play during the year ended December 31, 2012, we will continue to integrate these areas and increase our proved reserves through organic leasing as well as drilling on our existing undeveloped acreage.

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

Changes in PUDs. Changes in PUDS that occurred during the year ended December 31, 2012 were due to the following:

- Addition of approximately 311.0 Bcfe of Barnett Shale/Marble Fall and Mississippi Lime drilling locations acquired during 2012; and

- Negative revisions of approximately 18.5 Bcfe in PUDs primarily due to the reduction of drilling plans in the New Albany Shale formation over the next five years.

Development Costs. Costs incurred related to the development of PUDs were approximately $83.5 million, $40.5 million and $80.1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Productive Wells

The following table sets forth information regarding productive natural gas and oil wells in which we have a working interest as of December 31, 2012. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, directly or through our ownership interests in investment partnerships, and net wells are the sum of our fractional working interests in gross wells, based on the percentage interest we own in the investment partnership that owns the well:

	Number of productive wells(1)	
	Gross	**Net**
Appalachia:		
Gas wells	7,674	3,601
Oil wells	499	357
Total	8,173	3,958
Barnett/Marble Falls:		
Gas wells	552	455
Oil wells		
Total	552	455
Mississippi Lime/Hunton:		
Gas wells	45	37
Oil wells		
Total	45	37
Other operating areas(2):		
Gas wells	839	254
Oil wells	2	1
Total	841	255

Total:		
Gas wells	9,110	4,347
Oil wells	501	358
Total	9,611	4,705

(1) Includes our proportionate interest in wells owned by 96 investment partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 625 wells.

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Developed and Undeveloped Acreage

The following table sets forth information about our developed and undeveloped natural gas and oil acreage as of December 31, 2012. The information in this table includes our proportionate interest in acreage owned by investment partnerships.

	Developed acreage (1)		Undeveloped acreage (2)	
	Gross (3)	Net (4)	Gross (3)	Net (4)
Pennsylvania	138,852	133,347	3,430	3,427
Ohio(5)	82,566	81,206	31,408	31,399
Texas	61,348	56,443	73,367	60,717
Indiana	32,549	27,294	174,448	103,510
Oklahoma	32,438	12,186	2,235	1,161
Tennessee	19,691	19,315	97,603	95,339
New York	13,197	12,857	23,301	22,394
Other	17,390	15,693	3,900	3,695
Total	398,031	358,341	409,692	321,642

(1) Developed acres are acres spaced or assigned to productive wells.
(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether such acreage contains proved reserves.
(3) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.
(4) Net acres is the sum of the fractional working interests owned in gross acres. For example, a 50% working interest in an acre is one gross acre but is 0.5 net acres.
(5) Includes Utica Shale natural gas and oil rights on approximately 1,300 developed acres and new leases for undeveloped acres in Ohio covering approximately 2,600 acres.

The leases for our developed acreage generally have terms that extend for the life of the wells, while the leases on our undeveloped acreage have terms that vary from less than one year to five years. There are no concessions for undeveloped acreage as of December 31, 2012.

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

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

ITEM 3: LEGAL PROCEEDINGS

One of our subsidiaries entered into two agreements with the EPA, effective on September 25, 2012, to settle alleged violations in connection with a fire that occurred at a natural gas well and associated well pad site in Washington County, Pennsylvania in 2010. The EPA alleged non-compliance with the Clean Air Act, including with respect to the storage and handling of the natural gas condensate, as well as non-compliance with the Emergency Planning and Community Right-to-Know Act of 1986. Our subsidiary agreed to a civil penalty of $84,506 under a consent agreement and agreed to upgrade its facility pursuant to an administrative settlement agreement.

On August 3, 2011, CNX Gas Company LLC (CNX) filed a lawsuit in the United States District Court for the Eastern District of Tennessee at Knoxville styled *CNX Gas Company LLC vs. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC, and Scott Boruff*, No. 3:11-cv-00362. On April 16, 2012 Atlas Energy Tennessee, LLC, an indirect wholly-owned subsidiary, was brought in to the lawsuit by way of Amended Complaint. On April 23, 2012, the Court dismissed Chevron Appalachia, LLC as a party on the grounds of lack of subject matter jurisdiction over that entity.

The lawsuit alleges that CNX entered into a Letter of Intent with Miller Energy Resources, Inc. (Miller Energy) for the purchase by CNX of certain leasehold interests containing oil and natural gas rights, representing around 30,000 acres in East Tennessee. The lawsuit also alleges that Miller Energy breached the Letter of Intent by refusing to close by the date

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provided and by allegedly entertaining offers from third parties for the same leasehold interests. Allegations of inducement of breach of contract and related claims are made by CNX against the remaining defendants, on the theory that these parties knew of the terms of the Letter of Intent and induced Miller Energy to breach the Letter of Intent. CNX is seeking $15.5 million in damages. We assert that we acted in good faith and believe that the outcome of the litigation will be resolved in our favor.

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

ITEM 4: MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our common units began trading on March 14, 2012 and are listed on the New York Stock Exchange (NYSE) and are traded under the ticker symbol ARP . At the close of business on February 25, 2013, the closing price of our units was $23.15, and there were 215 holders of record of our common units. The following table sets forth the high and low sales price per unit of our common limited partner units as reported by the NYSE and the cash distributions declared by quarter per unit on our common limited partner units for the year ended December 31, 2012:

	High	Low	Cash Distribution per Common Limited Partner Declared(1)
Year ended December 31, 2012:			
Fourth quarter	$ 26.78	$ 21.23	$ 0.48
Third quarter	$ 28.23	$ 24.08	$ 0.43
Second quarter	$ 28.89	$ 23.15	$ 0.40
First quarter(2)	$ 31.97	$ 21.51	$ 0.12

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

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

We have a cash distribution policy under which we distribute, within 45 days after the end of each quarter, all of our available cash (as defined in the partnership agreement) for that quarter to our common unitholders and general partner. See Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Distribution Policy .

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

ITEM 6: SELECTED FINANCIAL DATA

The following table presents selected historical condensed combined financial data for us and our predecessor, Atlas Energy E&P Operations, as of and for the periods indicated. Atlas Energy E&P Operations consists of the subsidiaries of Atlas Energy that held its natural gas and oil development and production assets and liabilities and its partnership management business, substantially all of which Atlas Energy transferred to us on March 5, 2012. The condensed consolidated combined statement of operations data for the year ended December 31, 2012 and the condensed consolidated combined balance sheet data as of December 31, 2012 have been derived from our audited condensed combined financial statements included in Item 8: Financial Statements and Supplementary Data . The condensed combined statement of operations data for the years ended December 31, 2011 and 2010 and the condensed combined balance sheet data as of December 31, 2011 have been derived from Atlas Energy E&P Operations audited condensed combined financial statements

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included in Item 8: Financial Statements and Supplementary Data . The condensed combined statement of operations data for the years ended December 31, 2009 and 2008 and the condensed combined balance sheet data as of December 31, 2009 and 2008 are derived from Atlas Energy E&P Operations audited combined financial statements that are not included in this Form 10-K.

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

Recognized the assets acquired and liabilities assumed from the Transferred Business at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital/equity;

Retrospectively adjusted our consolidated combined financial statements for any date prior to February 17, 2011, the date of acquisition, to reflect our results on a consolidated combined basis with the results of the Transferred Business as of or at the beginning of the respective period; and

Adjusted the presentation of our consolidated combined statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners and the general partner. The Transferred Business historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by AEI to the underlying business segments, including the Transferred Business. We have reviewed AEI s general and administrative expense allocation methodology, which is based on the relative total assets of AEI and the Transferred Business, for the Transferred Business historical financial statements prior to the date of acquisition and believe the methodology is reasonable and reflects the approximate general and administrative costs of our underlying business segments.

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

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	(in thousands, except per unit data)				
Statement of operations data:					
Revenues:					
Gas and oil production	$ 92,901	$ 66,979	$ 93,050	$ 112,979	$ 127,083
Well construction and completion	131,496	135,283	206,802	372,045	415,036
Gathering and processing	16,267	17,746	14,087	18,839	19,098
Administration and oversight	11,810	7,741	9,716	15,554	19,277
Well services	20,041	19,803	20,994	17,859	18,513
Other, net	(4,886)	(30)			
Total revenues	267,629	247,522	344,649	537,276	599,007
Costs and expenses:					
Gas and oil production	26,624	17,100	23,323	25,557	25,104
Well construction and completion	114,079	115,630	175,247	315,546	359,609
Gathering and processing	19,491	20,842	20,221	25,269	19,098
Well services	9,280	8,738	10,822	9,330	10,654
General and administrative	69,123	27,536	11,381	15,832	13,074
Chevron transaction expense	7,670				
Depreciation, depletion and amortization	52,582	30,869	40,758	43,712	39,781
Asset impairment	9,507	6,995	50,669	156,359	
Total costs and expenses	308,356	227,710	332,421	591,605	467,320
Operating income (loss)	(40,727)	19,812	12,228	(54,329)	131,687
Interest expense	(4,195)				
Gain (loss) on asset sales and disposal	(6,980)	87	(2,947)		
Net income (loss)	(51,902)	19,899	9,281	(54,329)	131,687
Preferred limited partner dividends	(3,063)				
Net income (loss) attributable to owner s interest, common limited partners and the general partner	(54,965)	19,899	9,281	(54,329)	131,687
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 1,302,228	$ 520,883	$ 508,484	$ 503,386	$ 616,257
Total assets	1,498,952	702,366	649,232	690,603	834,260
Total debt, including current portion	351,425				
Total equity	862,006	457,175	381,882	351,586	515,622
Cash flow data:					
Net cash provided by operating activities	$ 16,486	$ 71,437	$ 60,586	$ 192,201	$ 169,278

Net cash used in investing activities	(644,278)	(47,509)	(92,423)	(98,393)	(262,153)
Net cash provided by (used in) financing activities	596,272	30,780	31,837	(93,808)	92,875
Capital Expenditures	(127,226)	(47,324)	(93,608)	(99,302)	(264,125)

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Operating data[1]					
Net production:					
Natural gas (Mcfd)	69,408	31,403	35,855	38,644	32,791
Oil (Bpd)	330	307	373	427	423
Natural gas liquids (Bpd)	974	444	499	101	
Total (Mcfed)	77,232	35,912	41,090	41,814	35,327
Average sales price:					
Natural gas (per Mcf) [2]:					
Realized price, after hedge[2]	$ 3.29	$ 4.98	$ 7.08	$ 7.54	$ 9.40
Realized price, before hedge[2]	$ 2.60	$ 4.53	$ 4.60	$ 4.04	$ 9.63
Oil (per Bbl):					
Realized price, after hedge	$ 94.02	$ 89.70	$ 77.31	$ 71.34	$ 92.28
Realized price, before hedge	$ 91.32	$ 89.07	$ 71.37	$ 57.41	$ 91.71
Natural gas liquids realized price (per Bbl)	$ 31.97	$ 48.26	$ 37.78	$ 36.19	$
Production costs (per Mcfe):					
Lease operating expenses[3]:	$ 0.82	$ 1.09	$ 1.27	$ 1.10	$ 1.06
Production taxes	0.12	0.10	0.04	0.03	0.03
Transportation and compression	0.24	0.43	0.65	0.68	0.85
Total	$ 1.19	$ 1.61	$ 1.96	$ 1.80	$ 1.94

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

(2) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the years ended December 31, 2012, 2011, 2010 and 2009. Including the effect of this subordination, the average realized gas sales price was $2.76 per Mcf ($2.08 per Mcf before the effects of financial hedging), $4.28 per Mcf ($3.83 per Mcf before the effects of financial hedging), $5.78 per Mcf ($3.30 per Mcf before the effects of financial hedging), and $7.13 per Mcf ($3.62 per Mcf before the effects of financial hedging) for the years ended December 31, 2012, 2011, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008.

(3) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our investment partnerships for the years ended December 31, 2012, 2011, 2010 and 2009. Including the effects of these costs, total lease operating expenses per Mcfe were $0.58 per Mcfe ($0.94 per Mcfe for total production costs), $0.77 per Mcfe ($1.33 per Mcfe for total production costs), $0.86 per Mcfe ($1.56 per Mcfe for total production costs), and $0.97 per Mcfe ($1.67 per Mcfe for total production costs) for the years ended December 31, 2012, 2011, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008.

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

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

Unless the context otherwise requires, references below to Atlas Resource Partners, L.P., Atlas Resource Partners, the partnership, we, us, and our company , when used for periods prior to March 5, 2012, refer to the subsidiaries and operations that Atlas Energy, L.P. contributed to Atlas Resource Partners in connection with the separation and, when used for periods after that date, refer to Atlas Resource Partners, L.P. and its consolidated subsidiaries. References below to Atlas Energy or ATLS refers to Atlas Energy, L.P. and its consolidated subsidiaries, unless the context otherwise requires.

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

BUSINESS OVERVIEW

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

At December 31, 2012, Atlas Energy, L.P. (ATLS), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of our general partner Class A units and incentive distribution rights through which it manages and effectively controls us, and an approximate 43.0% limited partner ownership interest (20,962,485 limited partner units) in us.

We were formed in October 2011 to own and operate substantially all of ATLS exploration and production assets (Atlas Energy E&P Operations), which were transferred to us on March 5, 2012. In February 2012, the board of directors of ATLS general partner approved the distribution of approximately 5.24 million of our common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 of our limited partner units for each of ATLS common units owned on the record date of February 28, 2012. The distribution of our limited partner units represented approximately 20% of the common limited partner units outstanding.

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

- AEI s investment management business, which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which we fund a portion of our natural gas and oil well drilling;
- proved reserves located in the Appalachia Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan, and the Chattanooga Shale of northeastern Tennessee; and
- certain producing natural gas and oil properties, upon which we are developers and producers.

FINANCIAL PRESENTATION

Our consolidated combined balance sheet at December 31, 2012 and the portion of the consolidated combined statement of operations for the year ended December 31, 2012 subsequent to the transfer of assets on March 5, 2012 include our accounts and our wholly-owned subsidiaries. Our combined balance sheet at December 31, 2011, the portion of the consolidated combined statements of operations for the year ended

December 31, 2012 prior to the transfer of assets on March 5, 2012 and the combined statement of operations for the years ended December 31, 2011 and 2010 were derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if we had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all the various entities comprising the combined financial statements, Atlas Energy s net investment in us is shown as equity in the combined financial statements. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated combined balance sheets and related consolidated combined statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management s best estimates, in order to derive our financial statements for the periods presented prior to the transfer of assets. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the combination of the financial statements.

Upon the acquisition of the Transferred Business on February 17, 2011, ATLS management determined that the acquisition constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable assets and liabilities of the Transferred Business with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital/equity. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the Transferred Business would have been included in our consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect of the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, we reflected the impact of the acquisition of the Transferred Business on our consolidated combined financial statements in the following manner:

- Recognized the assets acquired and liabilities assumed from the Transferred Business at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital/equity;

- Retrospectively adjusted our consolidated combined financial statements for any date prior to February 17, 2011, the date of acquisition, to reflect our results on a consolidated combined basis with the results of the Transferred Business as of or at the beginning of the respective period; and

- Adjusted the presentation of our consolidated combined statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners and the general partner. The Transferred Business historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by AEI to the underlying business segments, including the Transferred Business. We have reviewed AEI s general and administrative expense allocation methodology, which is based on the relative total assets of AEI and the Transferred Business, for the Transferred Business historical financial statements prior to the date of acquisition and believe the methodology is reasonable and reflects the approximate general and administrative costs of our underlying business segments.

SUBSEQUENT EVENTS

Cash Distribution. On January 24, 2013, we declared a cash distribution of $0.48 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2012. The $23.6 million distribution, including $0.6 million and $1.8 million to the general partner and preferred limited partners, respectively, was paid on February 14, 2013 to unitholders of record at the close of business on February 6, 2013.

Senior Notes. On January 23, 2013, we issued $275.0 million of 7.75% senior unsecured notes due on January 15, 2021 (7.75% Senior Notes). We used the net proceeds of approximately $268.3 million, net of underwriting fees and other offering costs of $6.7 million, to repay all of the indebtedness and accrued interest outstanding under our term loan credit facility and a portion of that outstanding under our revolving credit facility (see Credit Facilities). Under the terms of our revolving credit facility, the borrowing base was reduced by 15% of the 7.75% Senior Notes to $368.8 million. In connection with the retirement of our term loan credit facility and the reduction in our revolving credit facility borrowing base, we accelerated $2.2 million of amortization expense related to deferred financing costs in January 2013. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 18 months. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a make whole redemption price as defined in the indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. The indenture governing the 7.75% Senior Notes contains covenants, including limitations of our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets.

RECENT DEVELOPMENTS

DTE Acquisition. On December 20, 2012, we completed the acquisition of DTE Gas Resources, LLC from DTE Energy Company (NYSE: DTE; DTE) for $257.4 million, subject to certain post-closing adjustments (the DTE Acquisition). The cash paid at closing was funded through $179.8 million of borrowings under our revolving credit facility and $77.6 million through borrowings under our term loan credit facility.

Amendment to our revolving credit facility and new term loan credit facility. Also on December 20, 2012, in connection with the completion of the DTE Acquisition, we entered into an amendment to our revolving credit facility and a new term loan credit facility.

The amendment to our revolving credit facility:

- increased the borrowing base from $310.0 million to $410.0 million;
- stated that borrowings under the revolving credit facility bear interest, at our election, are at either LIBOR plus an applicable margin between 2.00% and 3.25% per annum or the base rate (which is the higher of the bank s prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.25% per annum;
- revised the maturity date to be the earlier of March 22, 2016 or February 19, 2014 (the date that is 91 days before the May 19, 2014 maturity date of our term loan credit facility) if any portion of the term loan debt is outstanding on that date; and
- amended the financial covenants to require that our ratio of Total Funded Debt (as defined in the credit agreement) to four quarters of EBITDA (as defined in the credit agreement) not be greater than 4.25 to 1.0 as of the last day of fiscal quarters ending on or before June 30, 2013, 4.00 to 1.0 as of September 30, 2013 and December 31, 2013, and 3.75 to 1.0 as of the last day of fiscal quarters ending after that date.

Our $77.6 term loan credit facility matures May 19, 2014, and contains terms substantially similar to our revolving credit facility except:

- our obligations are secured by second lien mortgages on our oil and gas properties and security interest in substantially all of our assets, and guarantees by substantially all of our subsidiaries;
- borrowings bear interest, at our option, at either the prime rate plus 6.5% or LIBOR plus 7.5%;
- we will be required to prepay borrowings with 100% of the net proceeds from any senior notes offering and 33% of the net proceeds from any equity offering; and
- requires us to maintain a ratio of Total Funded Debt to EBITDA 0.50 higher than that required under our revolving credit facility, a ratio of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.25 to 1.0 as of the last day of any fiscal quarter, and a minimum asset coverage ratio (as defined in the credit agreement) of at least 1.5 to 1.0.

We borrowed $179.8 million under our revolving credit facility and $77.6 million under our term loan facility to partially fund the DTE acquisition. We repaid the term loan credit facility in full with the proceeds from the sale of the 7.75% Senior Notes (see Subsequent Events).

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

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Acquisition of Titan Operating, L.L.C. In July 2012, we completed the acquisition of Titan Operating, L.L.C. (Titan) in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had an estimated collective value of $193.2 million, based upon the closing price of our publicly traded units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Issuance of Units). The cash paid at closing was funded through borrowings under our credit facility (see Credit Facilities). The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act) (see Issuance of Units).

Acquisition of Assets from Carrizo Oil & Gas, Inc. In April 2012, we acquired certain oil and natural gas assets from Carrizo Oil & Gas, Inc. (NASDAQ: CRZO; Carrizo) for approximately $187.0 million in cash. The purchase price was funded through borrowing under our credit facility and $119.5 million of net proceeds from the sale of 6.0 million of our common units at a negotiated purchase price per unit of $20.00, of which $5.0 million was purchased by certain of our executives. The common units were issued in a private transaction exempt from registration under Section 4(2) of the Securities Act (see Issuance of Units).

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

CONTRACTUAL REVENUE ARRANGEMENTS

Natural Gas. We market the majority of our natural gas production to gas utility companies, gas marketers, local distribution companies and industrial or other end-users. The sales price of natural gas produced is a function of the market in the area and typically tied to a regional index. The production area and pricing indexes are as follows: Appalachian Basin and Mississippi Lime, primarily the New York Mercantile Exchange (NYMEX) spot market price; Barnett Shale and Marble Falls, primarily the Waha spot market price; New Albany Shale and Antrim Shale, primarily the Texas Gas Zone SL and Chicago Hub spot market prices; and Niobrara formation, primarily the Cheyenne Hub spot market price.

We do not hold firm transportation obligations on any pipeline that requires payment of transportation fees regardless of natural gas production volumes. As is customary in certain of our other operating areas, we occasionally commit a predictable portion of monthly production to the purchaser in order to maintain a gathering agreement.

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. NGL s 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. The resulting dry natural gas is sold as mentioned above and our NGLs are generally priced using the Mont Belvieu (TX) regional processing hub. 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 volumetric 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, 2012, Chevron and Atmos Energy Marketing, LLC accounted for approximately 43% and 11% of our total natural gas, oil and NGL production revenues, respectively, with no other single customer accounting for more than 10% for this period.

Investment Partnerships. We generally fund a portion of our drilling activities through sponsorship of tax-advantaged investment drilling partnerships. In addition to providing capital for our drilling activities, our investment partnerships are a source of fee-based revenues, which are not directly dependent on commodity prices. As managing general partner of the investment partnerships, we receive the following fees:

Well construction and completion. For each well that is drilled by an investment partnership, we receive a 15% to 18% mark-up on those costs incurred to drill and complete the well;

Administration and oversight. For each well drilled by an investment partnership, we receive a fixed fee between $15,000 and $400,000, depending on the type of well drilled. Additionally, the 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 partnership pays us a monthly per well operating fee, currently $100 to $2,000, 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 wells; and

Gathering. Each royalty owner, 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 investment partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from Drilling Partnerships by approximately 3%.

GENERAL TRENDS AND OUTLOOK

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

The areas in which we operate are experiencing a significant increase in natural gas, oil and NGL production related to new and increased drilling for deeper natural gas formations and the implementation of new exploration and production techniques, including horizontal and multiple fracturing techniques. The increase in the supply of natural gas has put a downward pressure on domestic natural gas prices. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas, oil and NGL reserves.

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

RESULTS OF OPERATIONS

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various shale plays throughout the United States. As part of ATLS agreement with AEI to acquire the Transferred Business on February 17, 2011, we have certain agreements which restrict our ability to drill additional wells in certain areas of Pennsylvania, New York and West Virginia, including portions of the Marcellus Shale, which will expire on February 17, 2014. Through December 31, 2012, we have established production positions in the following operating areas:

the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas, a hydro-carbon producing shale in which we established a position following our acquisitions of assets from Carrizo, Titan and DTE during 2012 (see Recent Developments);

the Appalachia basin, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region;

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the Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area, in which we established a position following our acquisitions from Equal during 2012 (see Recent Developments); and

other operating areas, including the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; the Antrim Shale in Michigan, where we produce out of the biogenic region of the shale similar to the New Albany Shale; and the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled, both gross and for our interest, and the number of gross wells we turned in line during the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	**2011**	**2010**
Gross wells drilled:			
Appalachia	22	17	18
Barnett/Marble Falls	21		
Mississippi Lime/Hunton	11		
Tennessee		5	4
New Albany/Antrim			66
Niobrara	51	138	29
Total	105	160	117
Our share of gross wells drilled[(1)]:			
Appalachia	6	3	5
Barnett/Marble Falls	18		
Mississippi Lime/Hunton	3		
Tennessee		1	1
New Albany/Antrim			19
Niobrara	15	27	9
Total	42	31	34
Gross wells turned in line:			
Appalachia	41	8	70
Barnett/Marble Falls	7		
Mississippi Lime/Hunton	3		
Tennessee	5	1	13
New Albany/Antrim		13	76
Niobrara	98	77	8
Total	154	99	167

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in our investment partnerships.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes and production per day for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
Production:(1)(2)			
Appalachia:(3)			
Natural gas (MMcf)	12,403	9,597	11,596
Oil (000 s Bbls)	102	105	126
Natural gas liquids (000 s Bbls)	4	6	20
Total (MMcfe)	13,036	10,262	12,467
Barnett/Marble Falls:			
Natural gas (MMcf)	10,561		
Oil (000 s Bbls)	10		
Natural gas liquids (000 s Bbls)	173		

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Total (MMcfe)	11,661		
Mississippi Lime/Hunton:			
Natural gas (MMcf)	510		
Oil (000 s Bbls)	3		
Natural gas liquids (000 s Bbls)	30		
Total (MMcfe)	705		
Other Operating Areas[3]:			
Natural gas (MMcf)	1,929	1,866	1,491
Oil (000 s Bbls)	6	7	10
Natural gas liquids (000 s Bbls)	150	156	162
Total (MMcfe)	2,865	2,847	2,531
Total:			
Natural gas (MMcf)	25,403	11,462	13,087
Oil (000 s Bbls)	121	112	136
Natural gas liquids (000 s Bbls)	357	162	182
Total (MMcfe)	28,267	13,108	14,998
Production per day: [1][2]			
Appalachia:[3]			
Natural gas (Mcfd)	33,889	26,292	31,771
Oil (Bpd)	278	287	344
Natural gas liquids (Bpd)	10	17	54
Total (Mcfed)	35,618	28,116	34,157
Barnett/Marble Falls: [4]			
Natural gas (Mcfd)	28,855		
Oil (Bpd)	28		
Natural gas liquids (Bpd)	473		
Total (Mcfed)	31,861		
Mississippi Lime/Hunton: [4]			
Natural gas (Mcfd)	1,392		
Oil (Bpd)	8		
Natural gas liquids (Bpd)	81		
Total (Mcfed)	1,926		
Other Operating Areas: [3]			
Natural gas (Mcfd)	5,271	5,111	4,084
Oil (Bpd)	16	20	29
Natural gas liquids (Bpd)	410	427	445
Total (Mcfed)	7,827	7,796	6,933
Total:			
Natural gas (Mcfd)	69,408	31,403	35,855

Oil (Bpd)	330	307	373
Natural gas liquids (Bpd)	974	444	499
Total (Mcfed)	77,232	35,912	41,090

(1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the investment 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.

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

(3) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia. Other operating areas include our production located in the Chattanooga, New Albany/Antrim and Niobrara Shales.

(4) Total Barnett/Marble Falls and Mississippi Lime/Hunton production per day for the year ended December 31, 2012 represents volume production subsequent to the respective acquisition date over the full 366-day period (see Recent Developments).

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Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas, which comprised 79% of our proved reserves on an energy equivalent basis at December 31, 2012. 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, 2012, 2011 and 2010, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Years Ended December 31,		
	2012	2011	2010
Production revenues (in thousands):			
Appalachia:(1)			
Natural gas revenue	$ 35,193	$ 40,431	$ 66,566
Oil revenue	9,678	9,415	9,732
Natural gas liquids revenue	223	323	845
Total revenues	$ 45,094	$ 50,169	$ 77,143
Barnett/Marble Falls:			
Natural gas revenue	$ 25,545	$	$
Oil revenue	887		
Natural gas liquids revenue	4,959		
Total revenues	$ 31,391	$	$
Mississippi Lime/Hunton:			
Natural gas revenue	$ 1,840	$	$
Oil revenue	241		
Natural gas liquids revenue	1,140		
Total revenues	$ 3,221	$	$
Other Operating Areas: (2)			
Natural gas revenue	$ 7,573	$ 8,665	$ 9,064
Oil revenue	545	642	809
Natural gas liquids revenue	5,077	7,503	6,034
Total revenues	$ 13,195	$ 16,810	$ 15,907
Total:			
Natural gas revenue	$ 70,151	$ 49,096	$ 75,630
Oil revenue	11,351	10,057	10,541
Natural gas liquids revenue	11,399	7,826	6,879
Total revenues	$ 92,901	$ 66,979	$ 93,050
Average sales price:			
Natural gas (per Mcf): (3)			
Total realized price, after hedge(4)	$ 3.29	$ 4.98	$ 7.08
Total realized price, before hedge(4)	$ 2.60	$ 4.53	$ 4.60
Oil (per Bbl):			
Total realized price, after hedge	$ 94.02	$ 89.70	$ 77.31
Total realized price, before hedge	$ 91.32	$ 89.07	$ 71.37
Natural gas liquids (per Bbl) total realized price:	$ 31.97	$ 48.26	$ 37.78

Production costs (per Mcfe):[3]						
Appalachia:[1]						
Lease operating expenses[5]	$	1.02	$	1.20	$	1.37
Production taxes		0.08		0.11		0.03
Transportation and compression		0.38		0.50		0.73
	$	1.48	$	1.80	$	2.13
Barnett/Marble Falls:						
Lease operating expenses	$	0.61	$		$	
Production taxes		0.18				
Transportation and compression		0.12				
	$	0.90	$		$	
Mississippi Lime/Hunton:						
Lease operating expenses	$	1.38	$		$	
Production taxes		0.29				
Transportation and compression						
	$	1.67	$		$	
Other Operating Areas:[2]						
Lease operating expenses	$	0.63	$	0.67	$	0.78
Production taxes		0.06		0.07		0.06
Transportation and compression		0.17		0.19		0.30

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	$ 0.86	$ 0.93	$ 1.14
Total:			
Lease operating expenses(5)	$ 0.82	$ 1.09	$ 1.27
Production taxes	0.12	0.10	0.04
Transportation and compression	0.24	0.43	0.65
	$ 1.19	$ 1.61	$ 1.96

(1) Appalachia includes our operations located in Pennsylvania, Ohio, New York and West Virginia.

(2) Other operating areas include our production located in the Chattanooga, New Albany/Antrim and Niobrara Shales.

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

(4) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the years ended December 31, 2012, 2011 and 2010. Including the effect of this subordination, the average realized gas sales price was $2.76 per Mcf ($2.08 per Mcf before the effects of financial hedging), $4.28 per Mcf ($3.83 per Mcf before the effects of financial hedging) and $5.78 per Mcf ($3.30 per Mcf before the effects of financial hedging) for the years ended December 31, 2012, 2011 and 2010, respectively.

(5) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our investment partnerships for the years ended December 31, 2012, 2011 and 2010. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.48 per Mcfe ($0.94 per Mcfe for total production costs), $0.80 per Mcfe ($1.41 per Mcfe for total production costs) and $0.88 per Mcfe ($1.64 per Mcfe for total production costs) for the years ended December 31, 2012, 2011 and 2010, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $0.58 per Mcfe ($0.94 per Mcfe for total production costs), $0.77 per Mcfe ($1.33 per Mcfe for total production costs) and $0.86 per Mcfe ($1.56 per Mcfe for total production costs) for years ended December 31, 2012, 2011 and 2010, respectively.

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

Appalachia production costs were $12.4 million for the year ended December 31, 2012, a decrease of $2.0 million from $14.4 million for the year ended December 31, 2011. This decrease was principally due to a $2.9 million increase in our credit received against lease operating expenses pertaining to the subordination of our revenue within our investment partnerships, partially offset by a $0.9 million increase in labor and other costs. Production costs associated with our 2012 acquisitions in the Barnett Shale/Marble Falls and Mississippi Lime/Hunton plays were $11.7 million for the year ended December 31, 2012. Production costs associated with our other operating areas were $2.5 million for the year ended December 31, 2012, a decrease of $0.2 million from $2.7 million for the year ended December 31, 2011.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. Total natural gas revenues were $49.1 million for the year ended December 31, 2011, a decrease of $26.5 million from $75.6 million for the year ended December 31, 2010. This decrease consisted of a $24.0 million decrease attributable to lower realized natural gas prices and an $11.5 million decrease attributable to lower production volumes, partially offset by a $9.0 million decrease in gas revenues subordinated to the investor partners within our investment partnerships for the year ended December 31, 2011 compared with the prior year period. Total oil and natural gas liquids revenues were $17.9 million for the year ended December 31, 2011, an increase of $0.4 million from $17.5 million for the comparable prior year period. This increase resulted from a $1.4 million increase associated with higher average oil and natural gas liquids realized prices and a $0.9 million increase from the sale of natural gas liquids, partially offset by a $1.9 million decrease associated with lower oil production volumes. The decrease in natural gas and oil volumes was the result of fewer wells turned in line due to the cancellation of our fall 2010 drilling program, which was the result of AEI s announcement of the acquisition of the Transferred Business in November 2010. The decrease in gas revenues subordinated to the investor partners within our investment partnerships was related to the overall decrease in natural gas revenue.

Appalachia production costs were $14.4 million for the year ended December 31, 2011, a decrease of $6.0 million from $20.4 million for the year ended December 31, 2010. This decrease was principally due to a $3.6 million decrease in transportation costs, a $3.0 million decrease associated with water hauling and disposal costs, a $0.5 million decrease for labor-related costs and a $0.9 million decrease associated with maintenance expenses and other costs associated with our natural gas and oil operations, partially offset by a $2.0 million decrease in our credit received against lease operating expenses pertaining to the subordination of our revenue within our investment partnerships. The decreases in transportation costs, water hauling and disposal costs, labor-related costs and maintenance expenses and other costs were primarily due to a decrease in natural gas volumes between the periods. Production costs associated with our other operating areas were $2.7 million for the year ended December 31, 2011, a decrease of $0.2 million from $2.9 million for the year end December 31, 2010. The decrease was due to a $0.4 million decrease in maintenance and materials costs and a $0.2 million decrease in transportation costs, partially offset by a $0.4 million increase in water hauling and other costs.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our investment partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table presents the amounts of drilling partnership investor capital raised and deployed (in thousands), as well as the number of gross and net development wells we drilled for our investment partnerships during the years ended December 31, 2012, 2011 and 2010. There were no exploratory wells drilled during the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
Drilling partnership investor capital:			
Raised	$ 127,071	$ 141,929	$ 149,342
Deployed	$ 131,496	$ 135,283	$ 206,802
Gross partnership wells drilled:			
Appalachia	22	17	18
Barnett/Marble Falls	4		
Mississippi Lime/Hunton	11		
Tennessee		5	4
New Albany/Antrim			66
Niobrara	51	138	29
Total	88	160	117
Net partnership wells drilled:			
Appalachia	22	14	17
Barnett/Marble Falls	2		
Mississippi Lime/Hunton	9		
Tennessee		5	4
New Albany/Antrim			58
Niobrara	51	138	29
Total	84	157	108

Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for investment partnerships we sponsor. The following table sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Years Ended December 31,		
	2012	2011	2010
Average construction and completion:			
Revenue per well	$ 1,444	$ 886	$ 1,600
Cost per well	1,253	757	1,356

Gross profit per well	$ 191	$ 129	$ 244
Gross profit margin	$ 17,417	$ 19,653	$ 31,555
Partnership net wells associated with revenue recognized(1):			
Appalachia	17	17	34
Barnett/Marble Falls	2		
Mississippi Lime/Hunton	7		
Tennessee	2	4	10
New Albany/Antrim		3	63
Niobrara	63	129	22
Total	91	153	129

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

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Well construction and completion segment margin was $17.4 million for the year ended December 31, 2012, a decrease of $2.3 million from $19.7 million for the year ended December 31, 2011. This decrease consisted of a $7.9 million decrease related to a decreased number of wells recognized for revenue within our investment partnerships, partially offset by a $5.6 million increase associated with higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Marcellus Shale and Utica Shale wells within the drilling partnerships during 2012. Since our drilling contracts with the investment partnerships are on a cost-plus basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. Well construction and completion segment margin was $19.7 million for the year ended December 31, 2011, a decrease of $11.9 million from $31.6 million for the year ended December 31, 2010. This decrease consisted of a $14.9 million decrease associated with lower gross profit per well, partially offset by a $3.0 million increase related to an increased number of wells recognized for revenue within the investment partnerships. Average revenue and cost per well decreased between periods due to higher capital deployed for Niobrara formation wells within the drilling partnerships during 2011, while 2010 included higher capital deployment pertaining to Marcellus Shale and New Albany/Antrim Shale wells. Typically, the Niobrara formation wells we have drilled within the drilling partnerships have a lower cost per well as compared to the Marcellus Shale and New Albany/Antrim Shale wells. In addition, the decrease in well construction and completion margin was due to the cancellation of our Fall 2010 drilling program, which occurred following AEI s announcement of the acquisition of the Transferred Business in November 2010.

Our consolidated combined balance sheet at December 31, 2012 includes $67.3 million of liabilities associated with drilling contracts for funds raised by our investment partnerships that have not been applied to the completion of wells due to the timing of drilling operations, and thus had not been recognized as well construction and completion revenue on our consolidated combined statements of operations. We expect to recognize this amount as revenue during 2013.

Administration and Oversight

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our investment partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the drilling partnerships, such as those in the Niobrara Shale, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales.

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

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. Administration and oversight fee revenues were $7.7 million for the year ended December 31, 2011, a decrease of $2.0 million from $9.7 million for the year ended December 31, 2010. This decrease was primarily due to a decrease in the number of Marcellus Shale and New Albany Shale wells drilled during the current year period in comparison to the prior year period, partially offset by the increase in the number of wells drilled in the Niobrara Shale during the current year period in comparison to the prior year period. In addition, the decrease in administration and oversight revenues was due to the cancellation of our Fall 2010 drilling program, which occurred following AEI s announcement of the acquisition of the Transferred Business in November 2010.

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Well Services

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

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Well services revenues were $20.0 million for the year ended December 31, 2012, an increase of $0.2 million from $19.8 million for the year ended December 31, 2011. Well services expenses were $9.3 million for the year ended December 31, 2012, an increase of $0.6 million from $8.7 million for the year ended December 31, 2011. The increase in well services revenue is primarily related to higher equipment rental revenue during the year ended December 31, 2012 as compared with the comparable prior year period. The increase in well services expenses is primarily related to higher well labor costs.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. Well services revenues were $19.8 million for the year ended December 31, 2011, a decrease of $1.2 million from $21.0 million for year ended December 31, 2010. Well services expenses were $8.7 million for the year ended December 31, 2011, a decrease of $2.1 million from $10.8 million for the year ended December 31, 2010. The decrease in well services revenue and expense is primarily related to a reduction in repairs and maintenance projects due to fewer wells turned in line during the year ended December 31, 2011 as compared with the comparable prior year period.

Gathering and Processing

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

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

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. Our net gathering and processing expense for the year ended December 31, 2011 was $3.1 million compared with $6.1 million for the year ended December 31, 2010. This favorable decrease was principally due to lower natural gas volume and prices between the periods.

Other, net

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

OTHER COSTS AND EXPENSES

General and Administrative Expenses

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

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. General and administrative expenses were $27.5 million for the year ended December 31, 2011 compared with $11.4 million for the year ended December 31, 2010. The $16.1 million increase was principally due to a $4.9 million increase in office operations, a $5.0 million increase in salaries and wages, $1.8 million increase in syndication expenses related to the cancellation of our Fall 2010 drilling program and $4.4 million of outside services and other costs associated with the growth of our business.

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Chevron Transaction Expense

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

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization increased to $52.6 million for the year ended December 31, 2012 compared with $30.9 million for the comparable prior year period primarily due to a $19.6 million increase in our depletion expense. Total depreciation, depletion and amortization decreased to $30.9 million for the year ended December 31, 2011 compared with $40.8 million for the comparable prior year period primarily due to a $9.3 million decrease in our depletion expense. The following table presents a summary of our depreciation, depletion and amortization expense and our depletion expense per Mcfe for our operations for the respective periods:

	Years Ended December 31,		
	2012	**2011**	**2010**
Depreciation, depletion and amortization:			
Depletion expense	$ 47,000	$ 27,430	$ 36,668
Depreciation and amortization expense	5,582	3,439	4,090
	$ 52,582	$ 30,869	$ 40,758
Depletion expense (in thousands):			
Total	$ 47,000	$ 27,430	$ 36,668
Depletion expense as a percentage of gas and oil production revenue	51%	41%	39%
Depletion per Mcfe	$ 1.66	$ 2.09	$ 2.44

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties. For the year ended December 31, 2012, depletion expense was $47.0 million, an increase of $19.6 million in comparison with $27.4 million for the year ended December 31, 2011. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 51% for the year ended December 31, 2012, compared with 41% for the year ended December 31, 2011, which was primarily due to a decrease in realized natural gas prices between the periods. Depletion expense per Mcfe was $1.66 for the year ended December 31, 2012, a decrease of $0.43 per Mcfe from $2.09 for the year ended December 31, 2011, primarily related to lower depletion expense per Mcfe for the assets acquired from Carrizo, Titan and DTE Acquisitions (see Recent Developments) and the addition of reserves for new Marcellus Shale wells, which began production during the year ended December 31, 2012. Depletion expense increased between periods principally due to an overall increase in production volume.

For the year ended December 31, 2011, depletion expense decreased $9.3 million to $27.4 million compared with $36.7 million for the year ended December 31, 2010. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 41% for the year ended December 31, 2011, compared with 39% for the year ended December 31, 2010, which was primarily due to a decrease in realized natural gas prices between periods. Depletion expense per Mcfe was $2.09 for the year ended December 31, 2011, a decrease of $0.35 per Mcfe from $2.44 for the year ended December 31, 2010. Depletion expense decreased between periods principally due to the $50.7 million impairment of our Chattanooga and Upper Devonian Shale fields recorded during the three months ended December 31, 2010 and an overall decrease in production volumes.

Asset Impairment

During the year ended December 31, 2012, we recognized $9.5 million of asset impairment related to gas and oil properties within property, plant and equipment on our consolidated combined balance sheet for our shallow natural gas wells in the Antrim and Niobrara Shales. This impairment related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair value at December 31, 2012. The estimate of fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices in comparison to their carrying value at December 31, 2012.

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During the year ended December 31, 2011, we recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment on our combined balance sheet for our shallow natural gas wells in the Niobrara Shale. This impairment related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair value at December 31, 2011. The estimate of fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at December 31, 2011.

During the year ended December 31, 2010, we recognized $50.7 million of asset impairment related to gas and oil properties within property, plant and equipment on our combined balance sheet for our shallow natural gas wells in the Chattanooga and Upper Devonian Shales. This impairment related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair value at December 31, 2010. The estimate of fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices.

Interest Expense

Interest expense for the year ended December 31, 2012 was $4.2 million, which was associated with outstanding borrowings under our revolving credit facility and term loan credit facility and amortization of deferred financing costs associated with the credit facility (see Credit Facilities). There was no interest expense for the years ended December 31, 2011 and 2010.

Gain (Loss) on Asset Sales and Disposal

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

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. During the year ended December 31, 2011, we recognized a $0.1 million gain on asset sales and disposal, compared with a $2.9 million loss on asset sales and disposal during the year ended December 31, 2010. The $2.9 million loss on asset sales and disposal recognized during the year ended December 31, 2010 was primarily due to a loss on the sale of processing assets in Tennessee.

LIQUIDITY AND CAPITAL RESOURCES

General

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

Cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;

Expansion capital expenditures and working capital deficits through cash generated from operations, additional borrowings and capital raised through investment partnerships; and

Debt principal payments through additional borrowings as they become due or by the issuance of additional common units or asset sales.
We rely on cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve month period. However, we are subject to business, operational and other risks that

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could adversely affect our cash flow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional common units, the sale of assets and other transactions.

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

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

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

Net cash provided by financing activities of $596.3 million for the year ended December 31, 2012 represented a favorable movement of $565.5 million from net cash provided by financing activities of $30.8 million for the comparable prior year period. This movement was principally due to an increase of $667.1 million in borrowings under our revolving and term loan credit facilities and a $290.1 million increase in net proceeds from issuance of common limited partner units, partially offset by an increase of $315.7 million in repayments under our revolving and term loan credit facilities, a $33.9 million increase in cash distributions paid to unit holders, a net decrease of $25.1 million in the net investment from owners prior to March 5, 2012 and a $17.0 million unfavorable movement in deferred financing costs and other resulting from the cash paid for revolving and term loan credit facility financing costs. The net decrease in the net investment from owners was due to an increase of $5.6 million for the investment received from ATLS in 2012, partially offset by a decrease of $30.8 million in the net investment received in from AEI in 2011. The gross amount of borrowings and repayments under our revolving credit facility included within net cash provided by financing activities in the consolidated combined statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under our revolving credit facility, and payments, which generally occur throughout the period and increase borrowings under our revolving credit facility, which is generally common practice for our industry.

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

Cash Flows Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010

Net cash provided by operating activities of $71.4 million for the year ended December 31, 2011 represented a favorable movement of $10.8 million from net cash provided by operating activities of $60.6 million for the comparable prior year period. The $10.8 million favorable movement in net cash provided by operating activities resulted from a $20.6 million favorable movement in working capital, partially offset by a $9.8 million unfavorable movement in net income excluding non-cash items. The $20.6 million favorable movement in working capital was principally due to a $106.6 million favorable movement in accounts payable and other current liabilities, partially offset by an $86.0 million unfavorable movement in accounts receivable and other current assets, primarily due to an increase in subscriptions receivable for funds raised for our new drilling program in the fourth quarter of 2011. The $9.8 million unfavorable movement in net income excluding non-cash items included a $43.7 million unfavorable movement in asset impairment, $9.9 million unfavorable movement in depreciation, depletion and amortization expense and a $3.0 million decrease in loss on asset sales, partially offset by a $36.2 million favorable movement in non-cash gain on derivatives and a $10.6 million increase in net income.

Net cash used in investing activities of $47.5 million for the year ended December 31, 2011 represented a favorable movement of $44.9 million from net cash used in investing activities of $92.4 million for the comparable prior year period. This favorable movement was principally due to a $46.3 million favorable movement in capital expenditures. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities of $30.8 million for year ended December 31, 2011 represented an unfavorable movement of $1.1 million from net cash provided by financing activities of $31.8 million for the comparable prior year period. This movement was principally due to a net decrease in the net investment received from AEI.

Capital Requirements

Our capital requirements consist primarily of:

- maintenance capital expenditures capital expenditures we make on an ongoing basis to maintain our current levels of production and reserves over the long term; and

- expansion capital expenditures capital expenditures we make to increase our current levels of production and reserves for longer than the short-term and includes new leasehold interests and the development and exploitation of existing leasehold interests through acquisitions and investments in our drilling partnerships.

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

	Years Ended December 31,		
	2012	2011	2010
Maintenance capital expenditures	$ 10,200	$ 9,833	$
Expansion capital expenditures	117,026	37,491	93,608
Total	$ 127,226	$ 47,324	$ 93,608

During the year ended December 31, 2012, our $127.2 million of total capital expenditures consisted primarily of $54.4 million of investments in our investment partnerships compared with $28.2 million for the prior year comparable period, $28.1 for wells drilled exclusively for our own account compared with $0.6 million for the prior year comparable period, $33.4 million of leasehold acquisition costs compared with $9.5 million for the prior year comparable period, $1.9 million of gathering and processing costs compared with $3.2 million for the prior year comparable period, and $9.4 million of corporate and other compared with $5.8 million for the prior year comparable period. The increase in investments in our Drilling Partnerships was principally the result of the cancellation of the Fall 2010 drilling program and the resulting reduction of partnership capital deployed during 2011. Capital expenditures related to our investments in our Drilling Partnerships are generally incurred in the period subsequent to the period in which the funds were raised. The net increase in leasehold acquisition costs principally related to additional Marcellus Shale and Utica Shale acreage acquired through subsequent leasehold acquisitions in the region during the year ended December 31, 2012.

During the year ended December 31, 2011, our $47.3 million of total capital expenditures consisted primarily of $28.8 million of well costs, principally our investments in the investment partnerships, compared with $56.3 million for the prior year comparable period, $9.5 million of leasehold acquisition costs compared with $17.1 million for the prior year comparable period, $3.2 million of gathering and processing costs compared with $17.2 million for the prior year comparable period and $5.8 million of corporate and other compared with $3.0 million for the prior year comparable period. The decrease in investments in the investment partnerships and gathering and processing costs was the result of the cancellation of the Fall 2010 drilling program. Capital expenditures related to our investments in our Drilling Partnerships are generally incurred in the period subsequent to the period in which the funds were raised. Maintenance capital expenditures were $9.8 million during the year ended December 31, 2011. Prior to our acquisition of the Transferred Business on February 17, 2011, we had no maintenance capital requirements with regard to our gas and oil properties.

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We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisition, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of December 31, 2012, we are committed to expend approximately $33.7 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our investment partnerships and borrowings under our revolving credit facility.

OFF BALANCE SHEET ARRANGEMENTS

As of December 31, 2012, our off-balance sheet arrangements were limited to our letters of credit outstanding of $0.6 million and commitments to spend $33.7 million related to our drilling and completion and capital expenditures.

CASH DISTRIBUTION POLICY

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

Available cash will initially be distributed 98% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner, if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The incentive distribution rights will entitle our general partner to receive the following increasing percentage of cash distributed by us as it reaches certain target distribution levels:

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

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table summarizes our contractual obligations at December 31, 2012 (in thousands):

		Payments Due By Period			
Contractual cash obligations:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Total debt	$ 351,425	$	$ 75,425	$ 276,000	$
Interest on total debt	$ 33,026	$ 13,628	$ 17,693	$ 1,705	$
Operating leases	$ 11,989	$ 2,209	$ 3,414	$ 2,710	$ 3,656
Total contractual cash obligations	$ 396,440	$ 15,837	$ 96,532	$ 280,415	$ 3,656

		Amount of Commitment Expiration Per Period			
Other commercial commitments:	Total	Less than 1 Year	1 3 Years	4 5 Years	After 5 Years
Standby letters of credit	$ 622	$ 622	$	$	$
Other commercial commitments[1]	$ 11,914	$ 8,625	$ 1,189	$ 1,290	$ 810
Total commercial commitments	$ 12,536	$ 9,247	$ 1,189	$ 1,290	$ 810

(1) Our other commercial commitments include our share of drilling and completion commitments and our throughput contracts. We do not have firm transportation obligations on any pipeline that requires payment of transportation fees regardless of production volumes.

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ENVIRONMENTAL REGULATION

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

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

CHANGES IN PRICES AND INFLATION

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

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

CREDIT FACILITIES

At December 31, 2012, we had a senior secured revolving credit facility with a syndicate of banks with a borrowing base of $410.0 million with $276.0 million outstanding as well as a term loan credit facility with borrowings of $75.4 million. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $0.6 million was outstanding at December 31, 2012. On December 20, 2012, in connection with the completion of the DTE Acquisition, we entered into an amendment to our revolving credit facility and a new term loan credit facility. The amendment to our revolving credit facility:

- increased the borrowing base from $310.0 million to $410.0 million;
- stated that borrowings under the revolving credit facility bear interest, at our election, are at either LIBOR plus an applicable margin between 2.00% and 3.25% per annum or the base rate (which is the higher of the bank s prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.25% per annum;
- revised the maturity date to be the earlier of March 22, 2016 or February 19, 2014 (the date that is 91 days before the May 19, 2014 maturity date of our term loan credit facility) if any portion of the term loan debt is outstanding on that date; and

amended the financial covenants to require that our ratio of Total Funded Debt (as defined in the credit agreement) to four quarters of EBITDA (as defined in the credit agreement) not be greater than 4.25 to 1.0 as of the last day of fiscal quarters ending on or before June 30, 2013, 4.00 to 1.0 as of September 30, 2013 and December 31, 2013, and 3.75 to 1.0 as of the last day of fiscal quarters ending after that date.

Our new $77.6 million term loan facility matures May 19, 2014, and contains terms substantially similar to our revolving credit facility except:

- our obligations are secured by second lien mortgages on our oil and gas properties and security interest in substantially all of our assets, and guarantees by substantially all of our subsidiaries;

- borrowings bear interest, at our option, at either the prime rate plus 6.5% or LIBOR plus 7.5%;

- we will be required to prepay borrowings with 100% of the net proceeds from any senior notes offering, and 33% of the net proceeds from any equity offering; and

- requires us to maintain a ratio of Total Funded Debt to EBITDA 0.50 higher than that required under our revolving credit facility, a ratio of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.25 to 1.0 as of the last day of any fiscal quarter, and a minimum asset coverage ratio (as defined in the credit agreement) of at least 1.5 to 1.0.

We borrowed $179.8 million under our revolving credit facility and $77.6 million under our term loan facility to partially fund the DTE Acquisition. We repaid the term loan credit facility in full with the proceeds from the sale of the 7.75% Senior Notes (see Subsequent Events).

At December 31, 2012, the weighted average interest rate on outstanding credit facility borrowings was 2.8%, and the weighted average interest rate on outstanding term loan borrowings was 7.9%. There were no outstanding borrowings at December 31, 2011.

SECURED HEDGE FACILITY

At December 31, 2012, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership s ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

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

ISSUANCE OF UNITS

Equity Offerings

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

In July 2012, we completed the acquisition of certain proved reserves and associated assets in the Barnett Shale from Titan in exchange for 3.8 million of our common units and 3.8 million newly-created convertible Class B preferred units (which have an estimated collective value of $193.2 million, based upon the closing price of our publicly traded common units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments. The preferred units are voluntarily convertible to common units on a one-for-one basis within three years of the acquisition closing date at a strike

price of $26.03 plus all unpaid preferred distributions per unit, and will be mandatorily converted to common units on the third anniversary of the issuance. While outstanding, the preferred units will receive regular quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

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

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

Common Unit Distribution

In February 2012, the board of directors of ATLS general partner approved the distribution of approximately 5.24 million common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 limited partner units for each of ATLS common units owned on the record date of February 28, 2012. The distribution of these limited partner units represented approximately 20.0% of the common limited partner units outstanding.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Depreciation and Impairment of Long-Lived Assets and Goodwill

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

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

During the year ended December 31, 2012, we recognized $9.5 million of asset impairment related to gas and oil properties within property, plant and equipment on our consolidated combined balance sheet for shallow natural gas wells in the Antrim and Niobrara Shales. During the year ended December 31, 2011, we recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment on our consolidated combined balance sheet for shallow natural gas wells in the Niobrara Shale. During the year ended December 31, 2010, we recognized $50.7 million of asset impairment related to gas and oil properties within property, plant and equipment on our combined balance sheet for our shallow natural gas wells in the Chattanooga and Upper Devonian Shales. These impairments related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair value at December 31, 2012, 2011 and 2010. The estimate of fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

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

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

There were no goodwill impairments recognized by us during the years ended December 31, 2012, 2011 and 2010.

Fair Value of Financial Instruments

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

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

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

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

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

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

During the year ended December 31, 2012, we completed the acquisitions of certain oil and gas assets from Carrizo and reserves and associated assets from Titan and DTE. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were measured under our existing methodology for recognizing an estimated liability for the plugging and abandonment of our gas and oil wells (see Item 8: Financial Statements and Supplementary Date - Note 6). These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

Reserve Estimates

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

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

Asset Retirement Obligations

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

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

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular

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operating and financing activities and periodic use of derivative financial instruments such as forward contracts and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2012. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

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

Interest Rate Risk. At December 31, 2012, we had $276.0 million of borrowings under our revolving credit facility. We also had $75.4 million of borrowings under our term loan credit facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would have a $3.5 million impact on our consolidated combined interest expense for the twelve month period ending December 31, 2013.

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

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our consolidated combined operating income for the twelve-month period ending December 31, 2013 of approximately $7.9 million.

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

At December 31, 2012, we had the following commodity derivatives:

Natural Gas Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)
2013	22,729,700	$ 3.841
2014	19,233,000	$ 4.203
2015	13,434,500	$ 4.265
2016	12,866,300	$ 4.386
2017	6,480,000	$ 4.648

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Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)
2013	Puts purchased	5,520,000	$ 4.395
2013	Calls sold	5,520,000	$ 5.443
2014	Puts purchased	3,840,000	$ 4.221
2014	Calls sold	3,840,000	$ 5.120
2015	Puts purchased	3,480,000	$ 4.234
2015	Calls sold	3,480,000	$ 5.129

Natural Gas Put Options

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)
2013	Puts purchased	3,180,000	$ 3.450
2014	Puts purchased	1,800,000	$ 3.800
2015	Puts purchased	1,440,000	$ 4.000
2016	Puts purchased	1,440,000	$ 4.150

Natural Gas Liquids Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)
2013	57,000	$ 90.871
2014	21,000	$ 90.554

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)
2013	242,850	$ 91.532
2014	180,000	$ 91.579
2015	165,000	$ 88.436
2016	39,000	$ 86.120
2017	36,000	$ 84.600

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)(1)	Average Floor and Cap (per Bbl)(1)
2013	Puts purchased	65,000	$ 90.000
2013	Calls sold	65,000	$ 116.513
2014	Puts purchased	41,160	$ 84.169

2014	Calls sold	41,160	$	113.308
2015	Puts purchased	29,250	$	83.846
2015	Calls sold	29,250	$	110.654

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

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ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Resource Partners, L.P.

We have audited the accompanying consolidated combined balance sheets of Atlas Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (collectively the Partnership) as of December 31, 2012 and 2011, and the related consolidated combined statements of operations, comprehensive income(loss), changes in partners capital, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated combined financial statements referred to above present fairly, in all material respects, the financial position of Atlas Resource Partners, L.P. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2013 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

February 28, 2013

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED BALANCE SHEETS

(in thousands)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,188	$ 54,708
Accounts receivable	38,718	20,572
Current portion of derivative asset	12,274	13,801
Subscriptions receivable	55,357	34,455
Prepaid expenses and other	9,063	7,677
Total current assets	138,600	131,213
Property, plant and equipment, net	1,302,228	520,883
Intangible assets, net	1,320	1,501
Goodwill, net	31,784	31,784
Long-term derivative asset	8,898	16,128
Other assets, net	16,122	857
	$ 1,498,952	$ 702,366
LIABILITIES AND PARTNERS CAPITAL/EQUITY		
Current liabilities:		
Accounts payable	$ 59,549	$ 36,731
Advances from affiliates	5,853	1,253
Liabilities associated with drilling contracts	67,293	71,719
Current portion of derivative payable to Drilling Partnerships	11,293	20,900
Accrued well drilling and completion costs	47,637	17,585
Accrued liabilities	25,388	35,952
Total current liabilities	217,013	184,140
Long-term debt	351,425	
Long-term derivative liability	888	
Long-term derivative payable to Drilling Partnerships	2,429	15,272
Asset retirement obligations and other	65,191	45,779
Commitments and contingencies		
Partners Capital/Equity:		
General partner s interest	7,029	
Preferred limited partners interests	96,155	
Common limited partners interests	737,253	
Equity		427,246
Accumulated other comprehensive income	21,569	29,929
Total partners capital/equity	862,006	457,175
	$ 1,498,952	$ 702,366

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31, 2012	2011	2010
Revenues:			
Gas and oil production	$ 92,901	$ 66,979	$ 93,050
Well construction and completion	131,496	135,283	206,802
Gathering and processing	16,267	17,746	14,087
Administration and oversight	11,810	7,741	9,716
Well services	20,041	19,803	20,994
Other, net	(4,886)	(30)	
Total revenues	267,629	247,522	344,649
Costs and expenses:			
Gas and oil production	26,624	17,100	23,323
Well construction and completion	114,079	115,630	175,247
Gathering and processing	19,491	20,842	20,221
Well services	9,280	8,738	10,822
General and administrative	69,123	27,536	11,381
Chevron transaction expense	7,670		
Depreciation, depletion and amortization	52,582	30,869	40,758
Asset impairment	9,507	6,995	50,669
Total costs and expenses	308,356	227,710	332,421
Operating income (loss)	(40,727)	19,812	12,228
Interest expense	(4,195)		
Gain (loss) on asset sales and disposal	(6,980)	87	(2,947)
Net income (loss)	(51,902)	19,899	9,281
Preferred limited partner dividends	(3,063)		
Net income (loss) attributable to owner s interest, common limited partners and the general partner	$ (54,965)	$ 19,899	$ 9,281
Allocation of net income (loss):			
Portion applicable to owner s interest (period prior to the transfer of assets on March 5, 2012)	$ 250	$ 19,899	$ 9,281
Portion applicable to common limited partners and the general partner s interests (period subsequent to the transfer of assets on March 5, 2012)	(55,215)		
Net income (loss) attributable to owner s interest, common limited partners and the general partner	$ (54,965)	$ 19,899	$ 9,281
Allocation of net loss attributable to common limited partners and the general partner:			
Common limited partners interest	$ (54,260)	$	$

General partner s interest	(955)		
Net loss attributable to common limited partners and the general partner	$ (55,215)	$	$
Net loss attributable to common limited partners per unit:			
Basic	$ (1.59)	$	$
Diluted	$ (1.59)	$	$
Weighted average common limited partner units outstanding:			
Basic	34,039		
Diluted	34,039		

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
Net income (loss)	$ (51,902)	$ 19,899	$ 9,281
Preferred limited partner dividends	(3,063)		
Net income (loss) attributable to owner s interest, common limited partners and the general partner	(54,965)	19,899	9,281
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as cash flow hedges	10,921	35,156	16,542
Less: reclassification adjustment for realized gains in net income (loss)	(19,281)	(10,542)	(27,364)
Total other comprehensive income (loss)	(8,360)	24,614	(10,822)
Comprehensive income (loss) attributable to owner s interest, common limited partners and the general partner	$ (63,325)	$ 44,513	$ (1,541)

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENT OF PARTNERS CAPITAL/EQUITY

(in thousands, except unit data)

	General Partners Interest		Preferred Limited Partners Interests		Common Limited Partners Interests			Accumulated Other Comprehensive Income	Total Partners Capital/ Equity
	Class A Units	Amount	Units	Amount	Units	Amount	Equity		
Balance at January 1, 2010		$		$		$	$ 335,449	$ 16,137	$ 351,586
Net investment from Atlas Energy, Inc.							31,837		31,837
Other comprehensive loss								(10,822)	(10,822)
Net income							9,281		9,281
Balance at December 31, 2010		$		$			$ 376,567	$ 5,315	$ 381,882
Net investment from Atlas Energy, Inc.							30,780		30,780
Other comprehensive income								24,614	24,614
Net income							19,899		19,899
Balance at December 31, 2011		$		$		$	$ 427,246	$ 29,929	$ 457,175
Net income attributable to owner s interest prior to the transfer of assets on March 5, 2012							250		250
Net investment from owner s interest prior to the transfer of assets on March 5, 2012							5,625		5,625
Net assets contributed by owner to Atlas Resource Partners, L.P.	534,694	8,662			26,200,114	424,459	(433,121)		
Issuance of units	441,014		3,841,719	94,869	17,767,874	388,408			483,277
Unissued common units under incentive plans						10,797			10,797
Distributions paid to common and preferred limited partners and the general partner		(678)		(1,652)		(31,545)			(33,875)
Distribution equivalent rights paid on unissued units under incentive plan						(731)			(731)
Conversion of Class B preferred units			(5,165)	(125)	5,165	125			
Net income (loss) attributable to common and preferred limited partners and the general partner		(955)		3,063		(54,260)			(52,152)

subsequent to the transfer of assets on March 5, 2012									
Other comprehensive loss								(8,360)	(8,360)
Balance at December 31, 2012	975,708	$ 7,029	3,836,554	$ 96,155	43,973,153	$ 737,253	$	$ 21,569	$ 862,006

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (51,902)	$ 19,899	$ 9,281
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	52,582	30,869	40,758
Asset impairment	9,507	6,995	50,669
Non-cash (gain) loss on derivative value, net	(21,165)	36,171	
(Gain)/loss on asset sales and disposal	6,980	(87)	2,947
Non-cash compensation expense	10,828		
Amortization of deferred financing costs	1,820		
Changes in operating assets and liabilities:			
Accounts receivable and prepaid expenses and other	(35,835)	(32,203)	53,751
Accounts payable and accrued liabilities	43,671	9,793	(96,820)