Atlas Resource Partners, L.P.
Form 10-K
March 29, 2012
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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, 2011

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: **001-32953**

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, 4th Floor

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 ¨ No x

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. x

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

Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	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 equity securities held by non-affiliates of the registrant on March 14, 2012, based upon the closing price of $22.49 of the registrant s common units as reported on the New York Stock Exchange was approximately $117.8 million. The registrant has elected to use March 14, 2012 as the calculation date, which was the initial regular-way trading date of the registrant s common units on the New York Stock Exchange, since on June 30, 2011 (the last business day of the registrant s second fiscal quarter), the registrant was a privately-held company.

As of March 26, 2012, there were 26,200,000 common units outstanding.

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.

MLP. Master Limited Partnership.

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.

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.

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.

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Residue gas. The portion of natural gas remaining after natural gas is processed for removal of NGLs and impurities.

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

Statements contained in this document and other public documents or statements that are not historical facts may constitute forward-looking statements, including statements relating to the distribution, future revenues, future net income, future cash flows, financial forecasts, future market demand and future economic and industry conditions. Words such as expect, estimate, project, budget, forecast, anticipate, expect, plan, may, will, could, should, believe, predict, potential, continue and similar expressions are also intended to ident statements. We believe that our expectations are reasonable and are based on reasonable assumptions. However, such forward-looking statements by their nature involve risks and uncertainties that could cause actual results to differ materially from the results predicted or implied by the forward-looking statement. Some of the key factors that could cause our actual results to differ from our expectations include, but are not limited to:

- 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;

our lack of experience in drilling natural gas wells and the limited information available regarding reserves and decline rates in certain areas in which the assets to be acquired in connection with the distribution are located, including in the Marcellus Shale;

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 potential introduction of Pennsylvania severance taxes;

changes and potential changes in the regulatory and enforcement environment in the areas in which we will 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;

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 its business and operations;
- exposure to new and existing litigation;
- the potential failure to retain certain key employees and skilled workers;
- development of alternative energy resources; and
- the various risks and other factors considered by the board of directors of our general partner.

The foregoing list is not exclusive. Other factors that could cause actual results to differ from those implied by the forward-looking statements in this document are more fully described in Item 1A: Risk Factors of this annual report. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included or incorporated by reference in this document speak only as of the date on which the statements were made. 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 except as required by law.

Other factors not identified above, including the risk factors described in the section entitled Risk Factors included elsewhere in this annual report, may also cause actual results to differ materially from those projected by our forward-looking statements. Most of these factors are difficult to anticipate and are generally beyond our reasonable control.

You should consider the areas of risk described above, as well as those set forth in Item 1A: Risk Factors , in connection with considering any forward-looking statements that may be made by us and our businesses generally. We undertake no obligation to publicly release any revisions to any forward-looking statements, to report events or to report the occurrence of unanticipated events except as required by law.

PART I

ITEM 1: BUSINESS

Separation From Atlas Energy

We are a Delaware limited partnership formed in October 2011. At December 31, 2011, we were wholly-owned by Atlas Energy, L.P. (Atlas Energy), a publicly-traded master limited partnership (NYSE: ATLS). In February 2012, the board of directors of the general partner of Atlas Energy approved the distribution of approximately 5.24 million of our common units, which were distributed on March 13, 2012 to Atlas Energy s unitholders using a ratio of 0.1021 of our limited partner units for each Atlas Energy common unit owned on the record date of February 28, 2012. In connection with the distribution, the board of directors of the general partner of Atlas Energy also approved the transfer to us of Atlas Energy s E&P Operations. The distribution of our limited partner units represented approximately 19.6% of our outstanding limited partner interests. Subsequent to the distribution, Atlas Energy owns a 2% general partner interest, all of our incentive distribution rights and common units representing an approximate 78.4% limited partner interest in us. Our common units began trading regular-way under the ticker symbol ARP on the New York Stock Exchange on March 14, 2012.

In connection with the separation from Atlas Energy and distribution of our units, we expect to incur one-time expenditures between approximately $2.0 million and $4.0 million. These expenditures primarily consist of one-time transaction-related costs. We expect to fund these costs through cash from operations, cash on hand and, if necessary, cash available from our new credit facility. Additionally, we will incur increased costs as a result of becoming an independent, publicly traded company, primarily from establishing or expanding the corporate support for our business. We believe cash flows from operations will be sufficient to fund these additional corporate expenses.

We do not anticipate that increased costs solely from becoming an independent, publicly traded company will have an adverse effect on our growth rate in the future.

General

We, through the Atlas Energy E&P Operations transferred to us on March 13, 2012, are an independent developer and producer of natural gas and oil, with operations in the Appalachian Basin, Illinois Basin and the Rocky Mountain region. We

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sponsor and manage tax-advantaged investment partnerships, in which we coinvest, to finance a portion of our natural gas and oil production activities. Our goal is to increase the distributions to our unitholders by continuing to grow the net production from our natural gas and oil production business as well as the fee-based revenues from our partnership management business.

Atlas Energy, together with its predecessors and affiliates, has been involved in the energy industry since 1968. Our general partner is Atlas Resource Partners GP, LLC, a wholly owned subsidiary of Atlas Energy. Through our general partner, the Atlas Energy personnel currently responsible for managing our assets and capital raising will continue to do so on our behalf.

Basis of Presentation

As Atlas Energy did not contribute its ownership interest in the Atlas Energy E&P Operations to us until after the completion of the historical periods covered by this Form 10-K, we, as the registrant, have provided our stand-alone financial statements within Item 8: Financial Statements and Supplementary Data . We have also provided the combined financial statements of the Atlas Energy E&P Operations. As such, the remainder of the discussion within this section will reflect the Atlas Energy E&P Operations business transferred to us on March 13, 2012.

Atlas Energy E&P Operations

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

- 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.

As of December 31, 2011, our principal development and production assets consisted of:

- working interests in approximately 8,500 gross producing natural gas and oil wells;
- overriding royalty interests in over 500 gross producing natural gas and oil wells;
- net daily production of 35.9 Mmcfed for the twelve months ended December 31, 2011;
- proved reserves of 167.6 Bcfe at December 31, 2011; and
- our partnership management business, which includes equity interests in 98 investment partnerships and a registered broker-dealer that acts as the dealer-manager of our investment partnership offerings.

Our operations include three reportable operating segments: gas and oil production, well construction and completion and other partnership management.

SUBSEQUENT EVENTS

Acquisition of Assets from Carrizo Oil & Gas, Inc. On March 15, 2012, we entered into a definitive agreement with Carrizo Oil & Gas, Inc. to purchase certain assets for $190 million in cash (the Acquisition). The purchase price is subject to certain post-closing adjustments based on, among other things, environmental and title defects, if any. The assets being acquired include interests in approximately 200 natural gas wells producing from the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas, and related proved undeveloped acres as well as gathering pipelines and associated gathering facilities that service certain of the acquired wells. The closing of the Acquisition is expected to occur on or before April 30, 2012, and is subject to customary closing conditions.

To partially fund the Acquisition, on March 15, 2012 we executed a unit purchase agreement with several purchasers for the sale of 6.0 million of our common units at a negotiated purchase price per unit of $20.00, for anticipated gross proceeds of $120.0 million. The issuance of the common units is subject to customary closing conditions, including the closing of the Acquisition.

On March 15, 2012, we executed a commitment letter with Wells Fargo Bank, N.A., as administrative agent for the lenders under the credit facility, for the purpose of amending the facility to increase the borrowing base to $250.0 million and the maximum lender commitment to $500.0 million. The closing of the amendment to the facility is expected to occur on or before April 30, 2012, and is subject to customary closing conditions, including the closing of the Acquisition.

Credit Facility. On March 5, 2012, Atlas Energy s credit facility was amended and restated so that it assigned, and we assumed, Atlas Energy s rights, privileges and obligations under the credit facility. Subject to the March 15, 2012 commitment letter described above, the credit facility continues to have maximum lender commitments of $300 million, a borrowing base of $138 million and matures in March 2016. Up to $20.0 million of the credit facility may be in the form of standby letters of credit. Our obligations under the facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets. Additionally, our obligations under the facility are guaranteed by substantially all of our subsidiaries. Borrowings under the credit facility bear interest, at our election, at either LIBOR plus an applicable margin between 2.00% and 3.25% 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%. We are also required to pay a fee of 0.5% per annum on the unused portion of the borrowing base, which is included within interest expense on our combined statements of operations.

The credit agreement contains customary covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. The credit agreement also requires us to maintain a ratio of Total Funded Debt (as defined in the credit agreement) to four quarters (actual or annualized, as applicable) of EBITDA (as defined in the credit agreement) not greater than 3.75 to 1.0 as of the last day of any fiscal quarter, a ratio of current assets (as defined in the credit agreement) to current liabilities (as defined in the credit agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter, and a ratio of four quarters (actual or annualized, as applicable) of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.5 to 1.0 as of the last day of any fiscal quarter.

Secured Hedge Facility. On March 5, 2012, we entered into a secured hedge facility agreement with a syndicate of banks under which certain of our recently formed investment partnerships are eligible to participate in our hedging arrangements. The secured hedge facility agreement contains covenants that limit each of the participating investment 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.

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 program of sponsoring investment partnerships to exploit our acreage opportunities provides us with enhanced economic returns. For the five year period ended December 31, 2011, we raised over $1.4 billion from outside investors through our investment partnerships. We intend to continue to finance the majority of our drilling and production activities through our investment partnerships.

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 can increase our cash available for distribution. We will continue to seek strategic opportunities in our current areas of operation, as well as other regions of the United States.

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, 2011.

Continue to manage our exposure to commodity price risk. To limit our exposure to changing commodity prices, 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.

Competitive Strengths

We believe our competitive strengths favorably position us to execute our business strategy and to maintain and grow our distributions to unitholders. Our competitive strengths are:

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 15% to 18% markup on the investors well construction and completion costs and a fixed administration and oversight fee of $15,000 to $250,000. Further, we receive an approximate 5% to 10% 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.

Fee-based revenues from our investment partnerships provide a stable foundation for our distributions. Our investment partnerships provide us with stable, fee-based revenues which diminish the influence of commodity price fluctuations on our cash flows. Our fees for managing our investment partnerships accounted for approximately 41% of our segment margin in the twelve months ended December 31, 2011. 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.

We are one of the leading sponsors of tax-advantaged investment partnerships. We 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.

We have a high quality, long-lived reserve base. Our natural gas properties are located principally in 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 NYMEX for the natural gas we produce.

Through our general partner and its affiliates, we have significant experience in making accretive acquisitions. Through our general partner and its affiliates, 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.

Through our general partner and its affiliates, we have significant engineering, geologic and management experience. Atlas Energy s 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. The owner of our general partner has also recently added geologists and engineers to its 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.

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Geographic and Geologic Overview

Over the last decade, the energy industry in the United States has seen tremendous growth due to advancements in the technology to extract natural gas and oil from conventional and unconventional resource plays, which has made such extraction more economically attractive.

Our proved reserves, both developed and undeveloped, are concentrated in the following areas:

Appalachian Basin Overview. The Appalachian Basin includes the states of Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia and Tennessee. It is the most mature oil and natural gas producing region in the United States, having established the first oil production in 1860. 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. For the year ended December 31, 2011, the average premium over NYMEX for natural gas delivered to our primary delivery points in the Appalachian Basin was $0.36 per million British thermal units (MMBtu). 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, 2011.

Historically, producers in the Appalachian Basin developed oil and natural gas from shallow sandstones with low permeability which are prevalent in the region. These shallow wells are characterized by modest initial volumes, low pressures, and high initial decline rates followed by low annual decline rates. Almost all of these wells were drilled vertically and usually produce for 30 years or more. Shallow sandstone formations in the Appalachian Basin are typically homogenous and have a high degree of step-out development success. The primary shallow pay zones are shallow sandstones in the Upper Devonian Shale formation. As the step-out development progresses, reserves from newly completed wells are reclassified from proved undeveloped to proved developed and additional adjacent locations are added to proved undeveloped reserves. As a result, the cumulative amount of total proved reserves tends to increase as development progresses. Traditional shallow wells in the Appalachian Basin generally produce little or no water, contributing to a low cost of operation. In addition, most wells produce dry natural gas, which does not require processing.

In recent years, our predecessors and other operators have targeted the Marcellus Shale for development activity. 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 150 feet. As of December 31, 2011, we had an interest in Pennsylvania in approximately 221 wells, consisting of 207 vertical wells and 14 horizontal wells. An additional 24 wells, consisting of eight vertical wells and 16 horizontal wells, have been completed and are scheduled to be turned on-line during the first half of 2012.

As of December 31, 2011, we have drilled 11 Marcellus Shale wells and will be drilling an additional two Marcellus Shale wells during the first quarter of 2012 in West Virginia, all of which we are drilling through our partnership management business, consisting of seven vertical wells and six horizontal wells. We have maximized the lateral lengths of each of the horizontal wells based on lease boundaries. To date, there have been multiple Marcellus Shale wells drilled near our well sites that have shown strong initial production. Our future drilling activity in portions of the Appalachian Basin located in parts of Pennsylvania, West Virginia and New York will be limited by the terms of the non-competition agreements between certain of Atlas Energy s officers and directors and Chevron.

Additionally, as of December 31, 2011, we have leased additional Marcellus Shale acreage in Lycoming County, PA. We are currently drilling four additional Marcellus wells on this acreage through our partnership management program and have additional sites available to drill. We anticipate expanding our acreage in Lycoming County, which will give us the ability to drill additional wells.

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 425 wells in the region, 421 of which are funded through our investment partnerships and 30 of which are horizontal wells. Based on some recent successes around our leasehold acreage, we plan to drill additional horizontal wells during 2012. 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.

The Utica Shale is an Ordovician-age shale which lies several thousand feet below the Devonian-age Marcellus Shale. The Utica Shale is much thicker than the Marcellus Shale, and we believe has the potential to become a significant resource play. The Utica Shale begins in eastern Ohio and extends eastward, covering a large portion of Pennsylvania, New York and West Virginia. The Utica Shale has a western oil phase, central wet gas phase and eastern dry gas phase. We currently have an interest in approximately 2,100 wells in Ohio and operate three field offices which we intend to use for future Utica Shale development.

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Illinois Basin Overview. The Devonian-age New Albany Shale is a blanket formation 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, 2011, we have an interest in 92 wells in the New Albany Shale, of which we operate 90.

Denver-Julesburg Basin Overview. Within the Denver-Julesburg (DJ) 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 41 wells in the region, all of which were funded through our investment partnerships. We have run 3-D seismic imaging over a portion of the acreage subject to the farm-out agreement, which has identified over 600 potential drilling sites. Along with identifying potential Niobrara Shale drilling sites, the 3-D seismic imaging has allowed us to identify potential drilling sites in the D-Sand located under the Niobrara Shale. The D-Sand is a well-established exploration target in the Denver-Julesberg basin. The 3-D seismic imaging helps limit the potential of drilling dry holes while increasing drilling efficiency.

Gas and Oil Production

Production Volumes

Currently, our natural gas, oil and natural gas liquids production operations are focused in various shale plays in the northeastern and midwestern 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, 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	**2010**	**2009**
Production per day:(1)(2)			
Natural gas (Mcfd)	31,403	35,855	38,644
Oil (Bpd)	307	373	427
Natural gas liquids (Bpd)	444	499	101
Total (Mcfed)	35,912	41,090	41,814

(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 six Mcf s to one barrel.

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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 in the Appalachian Basin has been primarily based upon the NYMEX spot market price, the natural gas produced in the New Albany Shale and Antrim Shale has been primarily based upon the Texas Gas Zone SL and Chicago spot market prices, and the gas produced in the Niobrara formation has been primarily based upon the Cheyenne Index. Crude oil produced from our wells flows directly into storage tanks where it is picked up by an oil company, a common carrier or pipeline companies acting for an oil company, which is purchasing the crude oil. We sell any oil produced by our Appalachian wells to regional oil refining companies at the prevailing spot market price for Appalachian crude oil. Natural gas liquids are produced by our natural gas processing plants, which extract the natural gas liquids from the natural gas production, enabling the remaining dry gas (low BTU content) to meet pipeline specifications for long-haul transport to end users. We sell natural gas liquids produced by our natural gas processing plants to regional refining companies at the prevailing spot market price for natural gas liquids.

Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas, which comprised 94% of our proved reserves on an energy equivalent basis at December 31, 2011. 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, 2011, 2010 and 2009, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Years Ended December 31,		
	2011	2010	2009
Production revenues (in thousands):			
Natural gas revenue	$ 49,096	$ 75,630	$ 100,526
Oil revenue	10,057	10,541	11,119
Natural gas liquids revenue	7,826	6,879	1,334
Total revenues	$ 66,979	$ 93,050	$ 112,979
Average sales price:[(1)]			
Natural gas (per Mcf):			
Total realized price, after hedge[(2)]	$ 4.98	$ 7.08	$ 7.54
Total realized price, before hedge[(2)]	$ 4.53	$ 4.60	$ 4.04
Oil (per Bbl):			
Total realized price, after hedge	$ 89.70	$ 77.31	$ 71.34
Total realized price, before hedge	$ 89.07	$ 71.37	$ 57.41
Natural gas liquids (per Bbl) total realized price:	$ 48.26	$ 37.78	$ 36.19
Production costs (per Mcfe):[(1)]			
Lease operating expenses[(3)]	$ 1.06	$ 1.27	$ 1.10
Production taxes	0.10	0.04	0.03
Transportation and compression	0.46	0.65	0.68
Total	$ 1.61	$ 1.96	$ 1.80

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

(2) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the years ended December 31, 2011, 2010 and 2009. Including the effect of this subordination, the average realized gas sales prices were $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, 2011, 2010 and 2009, respectively.

(3) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our investment partnerships. Including the effects of these costs, total lease operating expenses per Mcfe were $0.75 per Mcfe ($1.30 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, 2011, 2010 and 2009, 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 natural gas and oil 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 $1.4 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**
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
2007	363.3	137.6	500.9
Total	$ 1,446.3	$ 463.1	$ 1,909.4

(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.

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 of between $15,000 and $250,000, 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 $1,500 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.

Gathering. Each royalty owner, partnership and certain other working interest owners pay us a gathering fee, which generally ranges from $0.35 per Mcf to the amount of the competitive gathering fee, currently defined as 13% of the gross sales price of the natural gas. In general, pursuant to gathering agreements we have with a third-party gathering system which gathers the majority of our natural gas, we must also pay an additional amount equal to the excess of the gathering fees collected from the investment partnerships up to an amount equal to approximately 16% of the realized natural gas sales price (adjusted for the settlement of natural gas derivative instruments). 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 investment 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.

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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, 2011, 2010 and 2009.

	Years Ended December 31,		
	2011	2010	2009
Gross wells drilled	160	117	267
Our share of gross wells drilled(1)	31	34	68

(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, 2011, we had the following ongoing drilling activities:

	Gross			Net		
	Spud	Total Depth	Completed	Spud	Total Depth	Completed
Marcellus Vertical		3	1		2	1
Marcellus Horizontal	2			2		
Chattanooga Vertical						
Chattanooga Horizontal		2	2		2	2
Niobrara Vertical	6	21	32	6	21	32
Ohio Vertical		3			3	

Natural Gas and Oil Leases

The typical natural gas and oil lease agreement provides for the payment of royalties to the mineral owner for all natural gas and oil produced from any well(s) drilled on the leased premises. In the Appalachian Basin and Colorado Basin, this amount is typically 1/8th (12.5%) resulting in a 87.5% net revenue interest to us, and, in Michigan, this amount is typically 1/6th (16.67%) resulting in an 83.3% net revenue interest to us. In certain instances, this royalty amount may increase to 1/6th in the Appalachian Basin and to 3/16th (18.75%) in Michigan when leases are taken from larger landowners or mineral owners such as coal and timber companies.

In almost all of the areas we operate in the Appalachian Basin, Colorado, Indiana and Michigan, the surface owner is normally the natural gas and oil owner allowing us to deal with a single owner. This simplifies the research process required to identify the proper owners of the natural gas and oil rights and reduces the per acre lease acquisition cost and the time required to successfully acquire the desired leases.

Because the acquisition of natural gas and oil leases is a very competitive process, and involves certain geological and business risks to identify productive areas, prospective leases are often held by other natural gas and oil operators. In order to gain the right to drill these leases, we may elect to farm-in leases and/or purchase leases from other natural gas and oil operators. Typically the assignor of such leases will reserve an overriding royalty interest, ranging in the Appalachian Basin and Colorado from 1/32nd to 1/16th (3.125% to 6.25%), which further reduces the net revenue interest available to us to between 84.375% and 81.25%, and in Michigan from 3.33% to 5.33%, which further reduces the net revenue interest available to us to between 80.0% and 78.0%.

The interests in some of our operated properties and of natural gas and oil leases retain the option to participate in the drilling of wells on leases farmed out or assigned to us for a retained working interest of up to 50% of the wells drilled on the covered acreage. In this event, our working interest ownership will be reduced by the amount retained by the third party. In all other instances, we anticipate owning a 100% working interest in newly drilled wells.

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Contractual Revenue Arrangements

Natural Gas. 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 in the Appalachian Basin has been primarily based upon the NYMEX spot market price, the natural gas produced in the New Albany Shale and Antrim Shale has been primarily based upon the Texas Gas Zone SL and Chicago spot market prices, and the gas produced in the Niobrara formation has been primarily based upon the Cheyenne Index. For the year ended December 31, 2011, Chevron, South Jersey Resources Group and Sequent Energy Management accounted for approximately 17%, 14% and 10% of our total natural gas and oil production revenues, respectively, with no other single customer accounting for more than 10% for this period.

Crude Oil. Crude oil produced from our wells flows directly into storage tanks where it is picked up by an oil company, a common carrier or pipeline companies acting for an oil company, which is purchasing the crude oil. We sell any oil produced by our Appalachian wells to regional oil refining companies at the prevailing spot market price for Appalachian crude oil.

Natural Gas Liquids. Natural gas liquids are produced by our natural gas processing plants, which extract the natural gas liquids from natural gas production, enabling the remaining dry gas (low BTU content) to meet pipeline specifications for long-haul transport to end users. We sell natural gas liquids produced by our natural gas processing plants to regional refining companies at the prevailing spot market price for natural gas liquids.

We do not have delivery commitments for fixed and determinable quantities of natural gas, oil or natural gas liquids in any future periods under existing contracts or agreements.

Investment Partnerships. We generally fund our drilling activities through sponsorship of tax-advantaged investment 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 natural gas and oil 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

We are party to two natural gas gathering agreements with Laurel Mountain Midstream, LLC (Laurel Mountain): (1) a Gas Gathering Agreement for Natural Gas on the Legacy Appalachian System with respect to the existing gathering systems and expansions to it (the Legacy Agreement) and (2) a Gas Gathering Agreement for Natural Gas on the Expansion Gathering System with respect to other gathering systems constructed within the specified area of mutual interest (the Expansion Agreement and, collectively with the Legacy Agreement, the Gathering Agreements). 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.

Under the Gathering Agreements, we are required to pay a gathering fee to Laurel Mountain that is the greater of $0.35 per mcf or 16% of the gross sales price except that a lower fee applies with respect to specific wells subject to existing contracts calling for lower minimum gathering fees and if Laurel Mountain fails to perform specified obligations. In addition, if an investment partnership pays a lesser competitive gathering fee for the natural gas it transports using Laurel Mountain s gathering system, which currently is 13% of the gross sales price, then we, and not the partnership, will have to pay the difference to Laurel Mountain.

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The Gathering Agreements require that, to the extent that we own wells or propose wells that are within 2,500 feet of Laurel Mountain s gathering system, we must at our cost construct up to 2,500 feet of flowline as necessary to connect the wells to the gathering system. For wells more than 2,500 feet from Laurel Mountain s gathering system, if we construct a flow line to within 1,000 feet of Laurel Mountain s gathering system, then Laurel Mountain must, at its own cost, extend its gathering system to connect to such flowline.

The Gathering Agreements remain in effect so long as gas from our wells is produced in economic quantities without lapse of more than 90 days.

Availability of Oil 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, 2011 and 2010, we faced no shortage of these goods and services. Over the past several years, we and other oil and natural gas companies have experienced higher drilling and operating costs. We cannot predict the duration or stability of the current level of supply and demand for drilling rigs and other goods and services required for our operations with any certainty due to numerous factors affecting the energy industry, including the demand for natural gas and oil.

We maintain certain agreements pursuant to which subsidiaries of Chevron have agreed to provide certain specified operational services for a limited period of time, including:

Pennsylvania Operating Services Agreement. Pursuant to this agreement, 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.

Petro-Technical Services Agreement. Pursuant to this agreement, a subsidiary of Chevron provides us with certain consulting services including, among others, planning, designing, drilling, stimulating, completing and equipping wells, in exchange for a payment in the amount of the actual costs of providing such services, up to a maximum of the market rate for the same or similar services in Pittsburgh, Pennsylvania or Traverse City, Michigan, depending on the location of the well. We will indemnify the provider against all claims and liabilities arising out of its provision of services under this agreement. The agreement remained in place at December 31, 2011.

Competition

The energy industry is intensely competitive in all of its aspects. 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. We also compete with the exploration and production divisions of public utility companies for natural gas and oil property acquisitions. Competition is intense for the acquisition of leases considered favorable for the development of natural gas and oil in commercial quantities. Our competitors may be able to pay more for natural gas and oil 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 natural gas and oil 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, 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 natural gas and oil 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.

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Markets

The availability of a ready market for natural gas, oil and natural gas liquids and the price obtained, depends upon numerous factors beyond our control, as described in Item 1A: Risk Factors Risks Relating to Our Business. Product availability and price are the principal means of competition in selling natural gas, oil and natural gas liquids. During the years ended December 31, 2011, 2010 and 2009, we did not experience problems in selling our natural gas, oil and natural gas liquids, although prices have varied significantly during those periods.

Seasonal Nature of Business

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. 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.

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 install wells, how we handle wastes 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 and production activities;
- limit or prohibit drilling activities on lands lying within or, in some cases, adjoining wilderness, wetlands and other protected areas;
- require remedial measures to reduce, mitigate or respond to releases of pollutants or hazardous substances from 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, 2011, 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 2012, or that will otherwise have a material impact on our financial position or results of operations.

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

Our operations are, in many cases, conducted at properties that have been used for natural gas and oil exploitation and production for many years. Although we believe we utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls on the discharge of pollutants, including produced waters and other natural gas and oil wastes, into navigable waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the relevant state. These permits may require pretreatment of produced waters before discharge. Compliance with such permits and requirements may be costly. Further, much of our natural gas extraction activity utilizes a process called hydraulic fracturing, which results in water discharges that must be treated and disposed of in accordance with applicable regulatory requirements. Recently, this subject has received much regulatory and legislative attention at both the federal and state level and we anticipate that the permitting and compliance requirements applicable to hydraulic fracturing activity are likely to become more stringent and could have a material adverse impact on our business and operations.

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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. Specific federal regulations applicable to the natural gas industry have been proposed under the New Source Performance Standards (NSPS) program along with National Emissions Standards for Hazardous Air Pollutants (NESHAP s). Final NSPS and NESHAP rules are anticipated in the spring of 2012 and will likely 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, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

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 starting in 2011 with the initial reports due in 2012. This rule imposes additional reporting obligations on us.

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.

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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.

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 managed;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- 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. 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 $.03 per MCF on natural gas and $.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. While Pennsylvania has not imposed a severance tax, there is legislation that has been approved by the

Pennsylvania legislature and signed by the Governor that will impose an impact fee on oil and gas production. 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

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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.

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.

Employees

We do not directly employ any of the persons responsible for our management or operation. In general, personnel employed by Atlas Energy will manage and operate our business. We anticipate that approximately 406 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 registration statement on Form 10, our annual report on Form 10-K, 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 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-4th Floor, Pittsburgh, Pennsylvania 15275, telephone number (800) 251-0171. A complete list of our filings is available on the Securities and Exchange Commission s website at www.sec.gov. Any of our filings is also available at the Securities and Exchange Commission 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 to our separation from Atlas Energy. Other risks relate principally to the securities markets and ownership of our limited partnership interests. Partnership interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Risks Relating to Our Business

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

Our revenue, profitability and cash flow substantially depend upon the prices and demand for natural gas and oil. The natural gas 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;

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- 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, 2011, the NYMEX Henry Hub natural gas index price ranged from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $113.93 per Bbl to a low of $75.67 per Bbl. Between January 1, 2012 and March 23, 2012, the NYMEX Henry Hub natural gas index price ranged from a high of $3.10 per MMBtu to a low of $2.27 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $109.77 per Bbl to a low of $96.36 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.

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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.

We currently sell the majority of our natural gas production to a single customer. To the extent this customer reduces the volumes of natural gas it purchases from us, or ceases to purchase natural gas from us, upon the expiration of our existing sales contracts, our revenues could be negatively affected.

Certain of our subsidiaries sell gas produced in four key counties in southwest Pennsylvania to a subsidiary of Chevron Corporation pursuant to a gas marketing agreement with a term expiring in February 2014, and all of the gas produced by the wells in Michigan owned by the investment partnerships are marketed by a subsidiary of Chevron pursuant to an operating agreement between the parties. To the extent Chevron reduces the amount of natural gas it purchases from us upon the expiration of these contracts, or if the gas marketing agreement is terminated or the gas marketing services provided under the operating agreement are no longer provided, our revenues could be harmed in the event we are unable to sell to other purchasers at similar prices.

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.

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

As of December 31, 2011, leases covering approximately 23,781 of our 286,533 net undeveloped acres, or 8.3%, are scheduled to expire on or before December 31, 2012. An additional 15% and 9% are scheduled to expire in the years 2013 and 2014, respectively. If we are unable to renew these leases or any leases scheduled for expiration beyond their expiration date, on favorable terms, we will lose the right to develop the acreage that is covered by an expired lease and our production would decline, which would reduce our cash flows from operations.

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

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

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events and drilling conditions;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- formations with abnormal pressures;
- injury or loss of life;
- environmental accidents such as gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment or oil leaks, including groundwater contamination;
- fires, blowouts, craterings and explosions; and

uncontrollable flows of natural gas or well fluids.

Any one or more of the factors discussed above could reduce or delay our receipt of drilling and production revenues, thereby reducing our earnings, and could reduce revenues in one or more of our 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

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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 and physical hedges for our production. Physical hedges are not deemed hedges for accounting purposes because they require firm delivery of natural gas and are considered normal sales of natural gas. We generally limit these arrangements to smaller quantities than those projected to be available at any delivery point.

In addition, we may enter into financial hedges, which may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. 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 this hedging arrangement. 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.

With the objective of enhancing the predictability of future revenues, from time to time we enter into natural gas, natural gas liquids and crude oil derivative contracts. We account for these 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.

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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 recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The Dodd-Frank Wall Street Reform and Consumer Protection Act, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation. The CFTC finalized its regulations and has set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The financial reform legislation may also require us and to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts; materially alter the terms of derivative contracts; reduce the availability of derivatives to protect against risks we encounter; reduce our ability to monetize or restructure our derivative contracts in existence at that time; and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation or regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was 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:

- mistaken assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to integrate successfully or timely the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns;
- increased demands on existing personnel;
- customer or key employee losses at the acquired businesses; and
- the failure to realize expected growth or profitability.

The scope and cost of these risks may be materially greater than estimated at the time of the acquisition. 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.

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. Public hearings on the studies and proposed regulations were held in November 2011, with the public comment period for the proposed regulations closing in January 2012. Further, 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. Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic fracturing process. In December 2011, West Virginia enacted legislation imposing more stringent regulation of horizontal drilling. 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.

Although the process is not generally subject to regulation at the federal level, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices, and some federal regulation has taken place. The Environmental Protection Agency, or EPA, has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel as an additive under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation that would provide for federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic fracturing process could be introduced in the future. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates 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, 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, and 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 become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. 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 proposed rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA s proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of green completions for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. Final regulations are anticipated in the spring of 2012. Once finalized, these rules will likely require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, both houses of U.S. Congress have actively considered legislation to reduce emissions of greenhouse gases, and almost one-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 requires reporting of greenhouse gases or otherwise limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or 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.

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

In response to findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment 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 federal 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 GHG emissions reporting rule relating to natural gas processing, transmission, storage, and distribution activities, which requires reporting beginning in 2012 for emissions occurring in 2011. Additionally, in 2010, EPA issued rules to regulate GHG emissions through traditional major source construction and operating permit programs. These permitting programs require consideration of and, if deemed necessary, implementation of best available control technology to reduce GHG 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 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. Our ability to collect and dispose of water will affect our production, and 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.

A severance tax or impact fee in Pennsylvania could materially increase our liabilities.

While Pennsylvania has historically not imposed a severance tax (relating to the extraction of natural gas), with a focus on its budget deficit and the increasing exploration of the Marcellus Shale, various legislation has been proposed since 2008. In February 2012, Pennsylvania implemented an impact fee. This new law imposes an impact fee on all unconventional wells drilled in the Commonwealth of Pennsylvania in counties that elect to impose the fee. The 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. Based upon natural gas prices for 2011, operators will pay $50,000 per unconventional horizontal well. Unconventional vertical wells will pay a fee equal to twenty percent of the horizontal well fee and the impact fee will not apply to any unconventional vertical well that produces less than 90mcf per day. 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.

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 hazardous substances into the environment.

The operations of our wells and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

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

the federal Resource Conservation and Recovery Act (which we refer to as RCRA) and comparable state laws that impose requirements for the handling and disposal of waste, including produced waters, from our facilities; and

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the federal Comprehensive Environmental Response, Compensation, and Liability Act (which we refer to as 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 and Atlas Energy, Inc. (AEI) or at locations to which we and AEI have sent waste for disposal.

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. 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 hazardous substances have been disposed of or otherwise released. 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 and our subsidiaries may incur environmental costs and liabilities due to the nature of our and our subsidiaries businesses and the substances we and our subsidiaries handle. For example, an accidental release from one of our or our subsidiaries wells could subject us or the applicable subsidiary 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 and our subsidiaries compliance costs and the cost of any remediation that may become necessary. We or the applicable subsidiary 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. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon natural gas and oil wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of 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 would impose 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. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry who can spread these additional costs over a greater number of wells and 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. Prior to our separation from Atlas Energy, it raised $141.9 million, $149.3 million and $353.4 million in calendar years 2011, 2010 and 2009, respectively. 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, the current administration has proposed, among other tax changes, the repeal of certain oil and gas tax benefits, including the repeal of the percentage depletion allowance, the election to expense intangible drilling costs, the passive activity exception for working interests and the marginal production tax credit. These proposals may or may not be adopted. 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.

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 and Chairman of the Board and Chief Executive Officer of Atlas Energy, and Jonathan Cohen, who serves as our Vice Chairman of the Board and 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 AEI. The foregoing 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. The non-competition agreements also prohibit Edward Cohen and Jonathan Cohen, until February 17, 2013, from soliciting for employment, or hiring, any person who was employed by AEI before its merger with Chevron and became an employee of AEI or Chevron after the merger, subject to certain limited exceptions.

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.

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 under our credit facility, the lenders 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 under our credit facility 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, and our net income would decrease.

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.

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 will occur 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.

We had a material weakness in our internal control over financial reporting as a result of the fact that the financial statements for Atlas Energy E&P Operations that we previously filed did not include general and administrative expense for periods prior to February 17, 2011. If a material weakness persists, our ability to accurately report our financial results could be adversely affected.

Atlas Energy previously filed financial statements for Atlas Energy E&P Operations that did not include general and administrative expenses for periods prior to February 17, 2011, the date of the acquisition of the Transferred Business. Atlas Energy had filed such financial statements without such expenses because the Transferred Business was not managed as a separate business segment, and the prior filings stated that such general and administrative expenses were not included for this reason. We have revised the financial statements for Atlas Energy E&P Operations to include general and administrative expenses for periods prior to February 17, 2011 based on allocations that we and Atlas Energy believe reflect the approximate general and administrative costs of the underlying business segments.

The failure to include these general and administrative expenses in the prior filing is considered a material weakness in our internal control over financial reporting. We have taken steps to correct the failure leading to this material weakness. However, we may identify additional deficiencies in the financial reporting process that could give rise to significant deficiencies or other material weaknesses, and we cannot assure you that there will not be future material weaknesses.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Estimates of the reserves we received from Atlas Energy 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 were prepared by Atlas Energy s independent petroleum engineers. Over time, Atlas Energy s or our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of Atlas Energy s 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, they 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. Atlas Energy s and standardized measure are calculated using natural gas prices that do not include financial hedges. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves

on historical prices and costs. However, actual future net cash flows from our natural gas properties also will be affected by factors such as:

- actual prices we receive for natural gas;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- the amount and timing of our capital expenditures;
- 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.

We may have been able to receive better terms from unaffiliated third parties than the terms provided in our agreements with Atlas Energy.

The agreements related to our separation from Atlas Energy, including the separation and distribution agreement and other agreements, were negotiated in the context of our separation from Atlas Energy while we were still part of Atlas Energy and, accordingly, may not reflect terms that would have been reached between unaffiliated parties. The terms of the agreements that we negotiated in the context of our separation relate to, among other things, allocation of assets, liabilities, rights, indemnifications and other obligations between Atlas Energy and us as well as certain ongoing arrangements between Atlas Energy and us. If these agreements had been negotiated with unaffiliated third parties, they might have been more favorable to us.

We may not achieve some or all of the expected benefits of the separation.

We may not be able to achieve the full strategic and financial benefits expected to result from the separation, or such benefits may be delayed or not occur at all. These expected benefits include the following:

- The separation will facilitate deeper understanding by investors of the different businesses of Atlas Energy and our company, allowing investors to more transparently value the merits, performance and future prospects of each company, which could increase overall unitholder value;
- By creating a publicly traded class of equity securities that can be offered as consideration in acquisition transactions, the separation will create an acquisition currency in the form of units that will enable us to purchase developed and undeveloped resources to accelerate growth of the natural gas and oil development and production and partnership management businesses without diluting Atlas Energy unitholders participation in growth at Atlas Pipeline Partners L.P., a publicly traded partnership the general partner of which is owned by Atlas Energy. Current industry trends have created a significant opportunity for us to grow through the acquisition of assets

being sold to close the funding gap created by the success of low-risk unconventional resources;

The separation of the two companies will enhance the ability of both us and Atlas Energy to gain access to financing because the financial community will be able to focus separately on each of the respective businesses, which have different investment and business characteristics and different potentials for financial returns;

The separation and distribution will enable us to provide employees dedicated to our business with equity-based incentives linked solely to our company, as opposed to equity of Atlas Energy;

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If we are able to increase our distributions, Atlas Energy unitholders could benefit from both Atlas Energy s indirect general partner interest in us as well as its incentive distribution rights;

The separation will provide enhanced liquidity to holders of Atlas Energy common units, who will hold two separate publicly traded securities that they may seek to retain or monetize; and

Investors will have a more targeted investment opportunity by having equity in two separate companies with different investment and business characteristics, including opportunities for growth, capital structure, business model, and financial returns.

We may not achieve the anticipated benefits for a variety of reasons. There also can be no assurance that the separation will not adversely affect our business.

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:

the failure of securities analysts to cover our common units after the spin-off or changes in financial estimates by analysts;

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 78.4% limited partner 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.

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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 will receive reimbursement for the provision of various general and administrative services for our benefit. Payments for these services will 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.

Unitholders may have limited liquidity for their common units, and a trading market may not develop for the common units.

There are approximately 5.24 million of our publicly traded common units outstanding (excluding the common units held by Atlas Energy). We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. You may not be able to resell your common units at a price you find attractive, or at all. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the units.

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.

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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, then our general partner may adopt such amendments to our partnership agreement as it determines are necessary or appropriate to obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant) and permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rate that can be charged to customers by our subsidiaries or who fails to comply with the procedures instituted by our general partner to obtain proof of the U.S. federal income tax status.

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

Unlike the holders of common stock in a corporation, our common unitholders will have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Common unitholders will not elect our general partner or the members of its board of directors, and will have no right to elect our general partner or 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 will be 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 will 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 the tenth anniversary of the date of the distribution in a merger or in a sale of all or substantially all of its assets, or after the tenth anniversary of the date of the distribution 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.

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

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

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

We utilize some of the foregoing exemptions from the corporate governance requirements of the NYSE listing standards. As a result, 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. Atlas Energy owns approximately 20.96 million common units, which represents 80.0% of the outstanding common units and an approximately 78.4% limited partner interest in us. As a result, our general partner has the right to exercise this limited call right. Therefore, 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.

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, or the 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 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 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.

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.

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 will 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.

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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 and West Virginia. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all U.S. federal, foreign, state and local tax returns that may be required of such unitholder.

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

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

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

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

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

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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 78.4% limited partner 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 78.4% limited partner interest and all of the equity of Atlas Resource Partners GP, LLC, our general partner, which, in turn, owns 534,694 class A units representing a 2% general partner interest in us. Accordingly, Atlas Energy possesses a controlling 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;
- changes to the agreements relating to our separation from Atlas Energy;
- changes to any other agreements that may adversely affect us;
- the payment of dividends on our units; and
- determinations with respect to our tax returns.

In addition, as long as Atlas Energy owns a controlling interest in us, it will be able to approve or disapprove matters submitted to members for a vote irrespective of the vote of other holders of common units.

Atlas Energy is free to sell our general partner and/or a substantial portion of our common units to a third party, and, if it does so, our unitholders may not realize any change-of-control premium on our common units, and we may become subject to the control of a presently unknown third party.

Our partnership agreement does not restrict Atlas Energy from transferring all or a portion of its 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 its own choices and thereby influence the decisions taken by the board of directors and officers. In addition, Atlas Energy could sell a majority of our outstanding common units to a third party.

The ability of Atlas Energy to sell our general partner and/or a majority of our common units to a third party, with no requirement for a concurrent offer to be made to acquire all of the common units that are publicly traded, could prevent our unitholders from realizing any change-of-control premium on their common units. In addition, a presently unknown third party could acquire control of us as a result of such a sale. Such a third party may have conflicts of interest with other unitholders. Atlas Energy s voting control may discourage transactions involving a change of control of our partnership, including transactions in which unitholders might otherwise receive a premium for their units over the then-current market price.

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, each of which can affect the amount of cash that is distributed to unitholders;
- 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 our general partner s incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations;
- 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;

the owner of our general partner, as the holder of more than two-thirds of the outstanding common units, may exercise its right to purchase all of the common units not owned by it; and

our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement eliminates our general partner s fiduciary duties to holders of our common units.

Our partnership agreement contains provisions that eliminate any fiduciary standards to which our general partner, its officers and directors, and its affiliates could otherwise be held by state fiduciary duty laws. Instead, our general partner is accountable to us and our unitholders pursuant to the contractual standards set forth in our partnership agreement. In addition, the directors and officers of our general partner have a duty to manage our general partner in a manner beneficial to its owner,

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which is Atlas Energy, pursuant to the terms of Atlas Energy s limited partnership agreement. Our general partner and its affiliates may make a number of decisions either in their individual capacities, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner and its affiliates to consider only the interests and factors that they desire, and they have no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- how to allocate business opportunities among us and its affiliates;
- whether or not to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether or not to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether or not to consent to any merger or consolidation of us or amendment to our partnership agreement.

By accepting or purchasing a common unit, a unitholder agrees to be bound by the provisions of the partnership agreement, including the provisions discussed above and, pursuant to the terms of our partnership agreement, is treated as having consented to various actions contemplated in our partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary or other duties under Delaware law.

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 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.

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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 and our unitholders.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner.

Our partnership agreement contains provisions restricting the remedies available to unitholders for actions taken by our general partner or its affiliates, including its owner, officers and directors. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner, and its officers and directors, are required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard (including fiduciary standards) imposed by Delaware law or any other law, rule or regulation or at equity;

- provides that our general partner, and its officers and directors, will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed that the decision was not adverse to our interests;

- provides that our general partner, its owner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- any action by our general partner with respect to a transaction with an affiliate or the resolution of a conflict of interest between us or our limited partners, on the one hand, and our general partner and its affiliates (including Atlas Energy and its affiliates), on the other hand, will be deemed to be approved by all of our unitholders, and will not constitute a breach of our partnership agreement, if the action is either:

    1. approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

    2. approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

    3. on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

    4. fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (3) and (4) above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

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, 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, 2011. In accordance with prevailing accounting literature, we determined that the acquisition of the Transferred Business constituted a transaction between entities under common control, and as such, we retrospectively adjusted prior year amounts within the tables below (See Item 1: Business Basis of Presentation). Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids 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, 2011 is included as Exhibit 99.2 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 price for each month within the prior 12-month period, and are listed below as of the dates indicated:

	December 31,	
Unadjusted	**2011**	**2010**
Natural gas (per Mcf)	$ 4.12	$ 4.38
Oil (per Bbl)	$ 96.19	$ 79.43
Adjusted		
Natural gas (per Mcf)(1)	$ 4.42	$ 4.63
Oil (per Bbl) (1)	$ 91.04	$ 72.70

(1) 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 price is the Base product price, adjusted for local contracted gathering arrangements. Natural gas liquid prices have not been presented as the reserve amounts are immaterial. 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. The accompanying reserve information included below was derived from the reserve reports prepared for Atlas Energy s annual report on Form 10-K for the year ended December 31, 2011. 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 Colorado, Indiana, New York, Ohio, Pennsylvania, Tennessee and West Virginia. The independent reserves engineer s evaluation was based on more than

35 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 Atlas Energy s Senior Reserve Engineer, who is a member of the Society of Petroleum Engineers and has more than 13 years of natural gas and oil industry experience. The reserve estimates were reviewed and approved by Atlas Energy s senior engineering staff and management, with final approval by our Executive 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. Please read Item 1A: Risk Factors Risks Relating to Our Business. You should not construe the estimated standardized measure values as 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.

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:

	0000000000000000	0000000000000000
	Proved natural gas and oil reserves at December 31,	
	2011	2010
Proved reserves:		
Natural gas reserves (Mmcf):		
Proved developed reserves	138,403	137,393
Proved undeveloped reserves(1)	19,273	38,672
Total proved reserves of natural gas	157,676	176,065
Oil reserves (Mbbl):		
Proved developed reserves	1,638	1,833
Proved undeveloped reserves(1)	8	
Total proved reserves of oil(2)	1,646	1,833
Total proved reserves (Mmcfe)	167,552	187,056
Standardized measure of discounted future cash flows (in thousands)(3)	$ 219,859	$ 236,630

(1) Our ownership in these reserves is subject to reduction as we generally make capital contributions, which includes leasehold acreage associated with our proved undeveloped reserves, to our 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.

(2) Includes less than 500 Mbbl of natural gas liquids proved reserves.

(3) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest and income tax expenses, or to depletion, depreciation and amortization. The future cash flows are discounted using an annual discount rate of 10%. Standardized measure does not give effect to commodity derivative contracts. Because we are a limited partnership, no provision for federal or state income taxes has been included in the December 31, 2011 and 2010 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, 2011, we had 76 PUD locations totaling approximately 19.3 Bcfe s of natural gas and oil. These PUDS are based on the definition of PUD s in accordance with the Securities and Exchange Commission 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.

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Historically, the primary focus of our drilling operations has been in the Appalachian Basin. We will continue to focus in this area to increase our proved reserves through organic leasing as well as drilling on our existing undeveloped acreage.

Our organic growth will focus on expanding our Marcellus Shale acreage position and targeting other formations in the United States. Through our previous drilling in the Marcellus as well as our geologic analysis of these areas, we are expecting these expansion locations to have a significant impact on our proved reserves. In addition, we have drilled successful Clinton formation natural gas and oil wells in eastern Ohio. We plan to continue drilling shallow Clinton wells.

In the Chattanooga Shale in Tennessee, where we have drilled more than 90 producing wells, we plan to increase our proved reserves through continued drilling activity in this area.

Changes in PUDs. Changes in PUDS that occurred during the year ended December 31, 2011 were due to the following:

Conversion of approximately 15.7 Bcfe from Marcellus Shale PUDs to proved developed reserves;

Addition of approximately 0.8 Bcfe of Marcellus, Clinton/Medina and Niobrara drilled locations; and

Negative revisions of approximately 4.5 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 $40.5 million, $80.1 million, and $80.2 million for the years ended December 31, 2011, 2010 and 2009, 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, 2011. 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:

	00000000000000000	00000000000000000
	Number of productive wells(1)	
	Gross	**Net**
Appalachia:		
Gas wells	7,715	3,198
Oil wells	498	314
Total	8,213	3,512
New Albany/Antrim:		
Gas wells	153	42
Oil wells		
Total	153	42
Niobrara:		
Gas wells	85	23

Oil wells		
Total	85	23
Total:		
Gas wells	7,953	3,263
Oil wells	498	314
Total	8,451	3,577

(1) Includes our proportionate interest in wells owned by 98 investment partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 514 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, 2011. The information in this table includes our proportionate interest in acreage owned by investment partnerships.

	000000000000000	000000000000000	000000000000000	000000000000000
	Developed acreage[1]		Undeveloped acreage[2]	
	Gross[3]	Net [4]	Gross[3]	Net [4]
Pennsylvania	154,492	154,492	758	758
Ohio[5]	104,612	75,619	31,608	31,608
Indiana	33,916	29,033	174,572	104,712
Tennessee	19,841	19,475	101,185	98,936
New York	13,197	12,699	43,697	42,379
Other	27,706	23,105	12,799	8,140
Total	353,764	314,423	364,619	286,533

(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) Does not include Utica Shale natural gas and oil rights.

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, 2011.

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

We are party to various routine legal proceedings arising in 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 Note 9 of Notes to the 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 . From March 14, 2012 through March 26, 2012, the highest sales price for our common units on the NYSE was $31.97 per unit and the lowest sales price for our common units on the NYSE was $21.51 per unit. On March 26, 2012, there were 199 holders of record of our common units.

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical condensed combined financial data for 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 hold 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 combined statement of operations data for the year ended December 31, 2011, 2010 and 2009 and the condensed combined balance sheet data as of December 31, 2011 and 2010 have been derived from Atlas Energy E&P Operations 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, 2008 and 2007 and the condensed combined balance sheet data as of December 31, 2009, 2008 and 2007 are derived from Atlas Energy E&P Operations audited combined financial statements that are not included in this Form 10-K.

The selected historical condensed combined financial and other operating data presented below should be read in conjunction with Atlas Energy E&P Operations audited combined financial statements and accompanying notes within Item 8: Financial Statements and Supplementary Data and Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations . Atlas Energy E&P Operations 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 periods presented, including changes that will occur in our operations and capitalization as a result of the separation from Atlas Energy and the distribution.

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(in thousands, except per unit data)				
Statement of operations data:					
Revenues:					
Gas and oil production	$ 66,979	$ 93,050	$ 112,979	$ 127,083	$ 99,015
Well construction and completion	135,283	206,802	372,045	415,036	321,471
Gathering and processing	17,746	14,087	18,839	19,098	13,781
Administration and oversight	7,741	9,716	15,554	19,277	17,955
Well services	19,803	20,994	17,859	18,513	16,663
Other, net	(30)				
Total revenues	247,522	344,649	537,276	599,007	468,885
Costs and expenses:					
Gas and oil production	17,100	23,323	25,557	25,104	17,638
Well construction and completion	115,630	175,247	315,546	359,609	279,540
Gathering and processing	20,842	20,221	25,269	19,098	13,781
Well services	8,738	10,822	9,330	10,654	9,062
General and administrative	27,536	11,381	15,832	13,074	9,864
Depreciation, depletion and amortization	30,869	40,758	43,712	39,781	28,388
Asset impairment	6,995	50,669	156,359		
Total costs and expenses	227,710	332,421	591,605	467,320	358,273
Operating income (loss)	19,812	12,228	(54,329)	131,687	110,612
Gain (loss) on asset sales	87	(2,947)			
Net income (loss)	19,899	9,281	(54,329)	131,687	110,612
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 520,883	508,484	$ 503,386	$ 616,257	$ 417,332

Total assets	701,113	649,232	690,603	834,260	520,003
Total debt, including current portion					

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Total equity	457,175	381,882	351,586	515,622	262,170
Cash flow data:					
Net cash provided by operating activities	$ 71,437	$ 60,586	$ 192,201	$ 169,278	$ 201,922
Net cash provided by (used in) investing activities	(47,509)	(92,423)	(98,393)	(262,153)	(156,442)
Net cash provided by (used in) financing activities	30,780	31,837	(93,808)	92,875	(45,480)
Capital Expenditures	(47,324)	(93,608)	(99,302)	(264,125)	(158,456)
Operating data(1)					
Net production:					
Natural gas (mcfd)	31,403	35,855	38,644	32,791	27,156
Oil (bpd)	307	373	427	423	418
Natural gas liquids (bpd)	444	499	101		
Total (mcfed)	35,912	41,090	41,814	35,327	29,664
Average sales price:					
Natural gas (per Mcf) (3):					
Realized price, after hedge(2)	$ 4.98	$ 7.08	$ 7.54	$ 9.40	$ 8.91
Realized price, before hedge(2)	$ 4.53	$ 4.60	$ 4.04	$ 9.63	$ 7.71
Oil (per Bbl):					
Realized price, after hedge	$ 89.70	$ 77.31	$ 71.34	$ 92.28	$ 70.11
Realized price, before hedge	$ 89.07	$ 71.37	$ 57.41	$ 91.71	$ 70.11
Natural gas liquids realized price (per Bbl)	$ 48.26	$ 37.78	$ 36.19	$	$
Production costs (per Mcfe):					
Lease operating expenses(3):	$ 1.06	$ 1.27	$ 1.10	$ 1.06	$ 0.86
Production taxes	0.10	0.04	0.03	0.03	0.03
Transportation and compression	0.46	0.65	0.68	0.85	0.74
Total	$ 1.61	$ 1.96	$ 1.80	$ 1.94	$ 1.63

(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, 2011, 2010 and 2009. Including the effect of this subordination, the average realized gas sales price was $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, 2011, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the years ended December 31, 2008 and 2007.

(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, 2011, 2010 and 2009. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.71 per Mcfe ($1.30 per Mcfe for total production costs), $0.83 per Mcfe ($1.54 per Mcfe for total production costs), and $0.95 per Mcfe ($1.66 per Mcfe for total production costs) for the years ended December 31, 2011, 2010 and 2009, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $0.75 per Mcfe ($1.30 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, 2011, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the years ended December 31, 2008 and 2007.

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

The historical financial statements included in this Annual Report reflect substantially all the assets, liabilities and operations of various wholly owned subsidiaries of Atlas Energy, L.P. (Atlas Energy) which were contributed to us prior to our separation from Atlas Energy in March 2012. We refer to these subsidiaries assets, liabilities and operations as Atlas Energy E&P Operations. The following discussion and analysis 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 stand-alone financial statements and the combined financial statements of the Atlas Energy E&P Operations.

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 in a historical context, refer to the subsidiaries and operations that Atlas Energy has contributed to Atlas Resource Partners in connection with the separation 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.

GENERAL

We are a Delaware limited partnership formed in October 2011. At December 31, 2011, we were wholly-owned by Atlas Energy, L.P. (Atlas Energy), a publicly-traded master limited partnership (NYSE: ATLS). In February 2012, the board of directors of the general partner of Atlas Energy approved the distribution of approximately 5.24 million of our common units, which were distributed on March 13, 2012 to Atlas Energy s unitholders using a ratio of 0.1021 of our limited partner units for each Atlas Energy common unit owned on the record date of February 28, 2012. In connection with the distribution, the board of directors of the general partner of Atlas Energy also approved the transfer to us of Atlas Energy s E&P Operations. The distribution of our limited partner units represented approximately 19.6% of our outstanding limited partner interests. Subsequent to the distribution, Atlas Energy owns a 2% general partner interest, all of our incentive distribution rights and common units representing an approximate 78.4% limited partner interest in us. Our common units began trading regular-way under the ticker symbol ARP on the New York Stock Exchange on March 14, 2012.

In connection with the separation from Atlas Energy and distribution of our units, we expect to incur one-time expenditures of between approximately $2.0 million and $4.0 million. These expenditures primarily consist of one-time transaction-related costs. We expect to fund these costs through cash from operations, cash on hand and, if necessary, cash available from our new credit facility. Additionally, we will incur increased costs as a result of becoming an independent, publicly traded company, primarily from establishing or expanding the corporate support for our business. We believe cash flows from operations will be sufficient to fund these additional corporate expenses.

We do not anticipate that increased costs solely from becoming an independent, publicly traded company will have an adverse effect on our growth rate in the future.

BASIS OF PRESENTATION

In February 2012, the Board also approved the transfer to us of the Atlas Energy E&P Operations from Atlas Energy. As Atlas Energy did not contribute its ownership interest in the Atlas Energy E&P Operations to us until after the completion of the historical periods covered by this Form 10-K, we, as the registrant, have provided our stand-alone financial statements within Item 8: Financial Statements and Supplementary Data . However, we have also provided the combined financial statements of the Atlas Energy E&P Operations. As such, the remainder of the discussion within this section will reflect the operating activities and results of operations of the Atlas Energy E&P Operations.

ATLAS ENERGY E&P OPERATIONS

We are an independent developer and producer of natural gas and oil, with operations in the Appalachian Basin, Illinois Basin and the Rocky Mountain region. We sponsor and manage tax-advantaged investment partnerships, in which we co-invest, to finance a portion of our natural gas and oil production activities.

On February 17, 2011, we acquired certain assets and liabilities (the Transferred Business) from Atlas Energy, Inc. (AEI), the former owner of Atlas Energy s general partner (see Recent Developments). These assets principally included the following exploration and production assets:

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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 combined financial statements were derived from the accounts of Atlas Energy and its wholly-owned subsidiaries. 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 our combined balance sheets and related combined statements of operations. Such estimates included allocations made from the historical accounting records of Atlas Energy, based on our best estimates, in order to derive our financial statements. 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.

In accordance with prevailing accounting literature, management of Atlas Energy determined that the acquisition of the Transferred Business constituted a transaction between entities under common control (see Recent Developments). In comparison to the purchase 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. Also, in comparison to the purchase method of accounting, whereby the results of operations and the financial position of the Transferred Business would have been included in our 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 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;

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

Adjusted the presentation of our combined statements of operations for the years ended December 31, 2011, 2010 and 2009 to reflect the results of operations attributable to the Transferred Business prior to the date of acquisition as a reduction of net income to determine income attributable to common limited partners. The Transferred Business historical financial statements prior to the date of acquisition reflect general and administrative expenses determined by AEI to the underlying business segments. 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 its underlying business segments.

SUBSEQUENT EVENTS

Acquisition of Assets from Carrizo Oil & Gas, Inc. On March 15, 2012, we entered into a definitive agreement with Carrizo Oil & Gas, Inc. to purchase certain assets for $190 million in cash (the Acquisition). The purchase price is subject to certain post-closing adjustments based on, among other things, environmental and title defects, if any. The assets being acquired include interests in approximately 200 natural gas wells producing from the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas, and related proved undeveloped acres as well as gathering pipelines and associated gathering facilities that service certain of the acquired wells. The closing of the Acquisition is expected to occur on or before April 30, 2012, and is subject to customary closing conditions.

To partially fund the Acquisition, on March 15, 2012 we executed a unit purchase agreement with several purchasers for the sale of 6.0 million of our common units at a negotiated purchase price per unit of $20.00, for anticipated gross proceeds of $120.0 million. The issuance of the common units is subject to customary closing conditions, including the closing of the Acquisition.

On March 15, 2012, we executed a commitment letter with Wells Fargo Bank, N.A., as administrative agent for the lenders under the credit facility, for the purpose of amending the facility to increase the borrowing base to $250.0 million and the maximum lender commitment to $500.0 million. The closing of the amendment to the facility is expected to occur on or before April 30, 2012, and is subject to customary closing conditions, including the closing of the Acquisition.

Credit Facility. On March 5, 2012, Atlas Energy s credit facility was amended and restated so that it assigned, and we assumed, Atlas Energy s rights, privileges and obligations under the credit facility. Subject to the March 15, 2012 commitment letter described above, the credit facility continues to have maximum lender commitments of $300 million, a borrowing base of $138 million and matures in March 2016. Up to $20.0 million of the credit facility may be in the form of standby letters of credit. Our obligations under the facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets. Additionally, our obligations under the facility are guaranteed by substantially all of our subsidiaries. Borrowings under the credit facility bear interest, at our election, at either LIBOR plus an applicable margin between 2.00% and 3.25% 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%. We are also required to pay a fee of 0.5% per annum on the unused portion of the borrowing base, which is included within interest expense on our combined statements of operations.

The credit agreement contains customary covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. The credit agreement also requires us to maintain a ratio of Total Funded Debt (as defined in the credit agreement) to four quarters (actual or annualized, as applicable) of EBITDA (as defined in the credit agreement) not greater than 3.75 to 1.0 as of the last day of any fiscal quarter, a ratio of current assets (as defined in the credit agreement) to current liabilities (as defined in the credit agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter, and a ratio of four quarters (actual or annualized, as applicable) of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.5 to 1.0 as of the last day of any fiscal quarter.

Secured Hedge Facility. On March 5, 2012, we entered into a secured hedge facility agreement with a syndicate of banks under which certain of our recently formed investment partnerships are eligible to participate in our hedging arrangements. The secured hedge facility agreement contains covenants that limit each of the participating investment 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.

RECENT DEVELOPMENTS

Acquisition from AEI. On February 17, 2011, Atlas Energy completed an acquisition of the Transferred Business from AEI, the former parent of its general partner. For the assets acquired and liabilities assumed, Atlas Energy issued approximately 23.4 million of its common limited partner units and paid $30.0 million in cash consideration. Based on Atlas Energy s February 17, 2011 common unit closing price of $15.92, the common units issued to AEI were valued at approximately $372.2 million. In connection with the transaction, Atlas Energy also received $118.7 million with respect to a contractual cash transaction adjustment from Chevron related to certain liabilities assumed by the Transferred Business, including certain amounts subject to a reconciliation period following the consummation of the transaction. Including the cash transaction adjustment, the net book value of the Transferred Business was approximately $522.9 million.

CONTRACTUAL REVENUE ARRANGEMENTS

Natural Gas. 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 in the Appalachian Basin has been primarily based upon the NYMEX spot market price, the natural gas produced in the New Albany Shale and Antrim Shale has been primarily based upon the Texas Gas Zone SL and Chicago spot market prices, and the gas produced in the Niobrara formation has been primarily based upon the Cheyenne Index. For the year ended December 31, 2011, Chevron, South Jersey Resources Group and Sequent Energy Management accounted for approximately 17%, 14% and 10% of our total natural gas and oil production revenues, respectively, with no other single customer accounting for more than 10% for this period.

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Crude Oil. Crude oil produced from our wells flows directly into storage tanks where it is picked up by an oil company, a common carrier or pipeline companies acting for an oil company, which is purchasing the crude oil. We sell any oil produced by our Appalachian wells to regional oil refining companies at the prevailing spot market price for Appalachian crude oil.

Natural Gas Liquids. Natural gas liquids (NGL s) are produced by our natural gas processing plants, which extract the natural gas liquids from the natural gas production, enabling the remaining dry gas (low BTU content) to meet pipeline specifications for long-haul transport to end users. We sell natural gas liquids produced by our natural gas processing plants to regional refining companies at the prevailing spot market price for natural gas liquids.

We do not have delivery commitments for fixed and determinable quantities of natural gas, oil or natural gas liquids in any future periods under existing contracts or agreements.

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 natural gas and oil 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 of between $15,000 and $250,000, 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 $1,500, 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 generally ranges from $0.35 per Mcf to the amount of the competitive gathering fee, currently defined as 13% of the gross sales price of the natural gas. In general, pursuant to gathering agreements we have with a third-party gathering system which gathers the majority of our natural gas, we must also pay an additional amount equal to the excess of the gathering fees collected from the investment partnerships up to an amount equal to approximately 16% of the realized natural gas sales price (adjusted for the settlement of natural gas derivative instruments). 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 investment 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.

Natural Gas Supply and Outlook. The areas in which we operate are experiencing a significant increase in natural gas 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. This increase in the supply of natural gas has put a downward pressure on domestic 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 reserves.

Reserve Outlook. 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 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.

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RESULTS OF OPERATIONS

GAS AND OIL PRODUCTION

Production Profile. Currently, we have focused our natural gas and oil production operations in various shale plays in the northeastern and midwestern United States. As part of our agreement with AEI to acquire the Transferred Business, we have entered into 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. Through December 31, 2011, we have established production positions in the following areas:

- the Appalachia basin, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and 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 Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas;
- the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; and
- the Antrim Shale in Michigan, where we produce out of the biogenic region of the shale similar to the New Albany Shale;

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 three years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	**2010**	**2009**
Gross wells drilled:			
Appalachia	22	22	174
New Albany/Antrim		66	93
Niobrara	138	29	
	160	117	267
Our share of gross wells drilled[(1)]**:**			
Appalachia	4	6	45
New Albany/Antrim		19	23
Niobrara	27	9	
	31	34	68
Gross wells turned in line:			
Appalachia	9	83	307
New Albany/Antrim	13	76	65
Niobrara	77	8	
	99	167	372

(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, oil, and natural gas liquids production volumes and production per day for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	**2010**	**2009**
Production:[(1)(2)]			
Appalachia:[(3)]			
Natural gas (MMcf)	10,163	12,363	13,905
Oil (000 s Bbls)	112	136	156
Natural gas liquids (000s Bbls)	162	182	37
Total (MMcfe)	11,809	14,274	15,062
New Albany/Antrim:			
Natural gas (MMcf)	1,148	724	200

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Oil (000 s Bbls)			
Natural gas liquids (000s Bbls)			
Total (MMcfe)	1,148	724	200
Niobrara:			
Natural gas (MMcf)	152		
Oil (000 s Bbls)			
Natural gas liquids (000s Bbls)			
Total (MMcfe)	152		
Total:			
Natural gas (MMcf)	11,462	13,087	14,105
Oil (000 s Bbls)	112	136	156
Natural gas liquids (000s Bbls)	162	182	37
Total (MMcfe)	13,108	14,998	15,262
Production per day: (1)(2)			
Appalachia:(3)			
Natural gas (Mcfd)	27,843	33,872	38,096
Oil (Bpd)	307	373	427
Natural gas liquids (Bpd)	444	499	101
Total (Mcfed)	32,352	39,107	41,267
New Albany/Antrim:			
Natural gas (Mcfd)	3,144	1,983	548
Oil (Bpd)			
Natural gas liquids (Bpd)			
Total (Mcfed)	3,144	1,983	548
Niobrara:			
Natural gas (Mcfd)	416		
Oil (Bpd)			
Natural gas liquids (Bpd)			
Total (Mcfed)	416		
Total:			
Natural gas (Mcfd)	31,403	35,855	38,644
Oil (Bpd)	307	373	427
Natural gas liquids (Bpd)	444	499	101
Total (Mcfed)	35,912	41,090	41,814

(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 six Mcf s to one barrel.

(3) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia and Tennessee.

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 94% of our proved reserves on an energy equivalent basis at December 31, 2011. 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, 2011, 2010, and 2009, along with our average production costs, taxes, and transmission and compression costs in each of the reported periods:

	Years Ended December 31,		
	2011	**2010**	**2009**
Production revenues (in thousands):			
Appalachia:[1]			
Natural gas revenue	$ 43,310	$ 71,726	$ 99,024
Oil revenue	10,057	10,541	11,119
Natural gas liquids revenue	7,826	6,879	1,334
Total revenues	$ 61,193	$ 89,146	$ 111,477
New Albany/Antrim:			

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Natural gas revenue	$ 5,154	$ 3,904	$ 1,502
Oil revenue			
Natural gas liquids revenue			
Total revenues	$ 5,154	$ 3,904	$ 1,502
Niobrara:			
Natural gas revenue	$ 632	$	$
Oil revenue			
Natural gas liquids revenue			
Total revenues	$ 632	$	$
Total:			
Natural gas revenue	$ 49,096	$ 75,630	$ 100,526
Oil revenue	10,057	10,541	11,119
Natural gas liquids revenue	7,826	6,879	1,334
Total revenues	$ 66,979	$ 93,050	$ 112,979
Average sales price:(2)			
Natural gas (per Mcf):			
Total realized price, after hedge(3)	$ 4.98	$ 7.08	$ 7.54
Total realized price, before hedge(3)	$ 4.53	$ 4.60	$ 4.04
Oil (per Bbl):			
Total realized price, after hedge	$ 89.70	$ 77.31	$ 71.34
Total realized price, before hedge	$ 89.07	$ 71.37	$ 57.41
Natural gas liquids (per Bbl) total realized price:	$ 48.26	$ 37.78	$ 36.19
Production costs (per Mcfe):(2)			
Appalachia:(1)			
Lease operating expenses(4)	$ 1.05	$ 1.25	$ 1.08
Production taxes	0.10	0.03	0.03
Transportation and compression	0.50	0.68	0.68
	$ 1.64	$ 1.97	$ 1.79
New Albany/Antrim:			
Lease operating expenses	$ 1.14	$ 1.59	$ 2.54
Production taxes	0.13	0.10	0.05
Transportation and compression	0.03	0.09	0.09
	$ 1.31	$ 1.77	$ 2.67
Niobrara:			
Lease operating expenses	$ 1.16	$	$
Production taxes	0.03		
Transportation and compression	0.43		
	$ 1.62	$	$
Total:			
Lease operating expenses(4)	$ 1.06	$ 1.27	$ 1.10
Production taxes	0.10	0.04	0.03
Transportation and compression	0.46	0.65	0.68

	$ 1.61	$ 1.96	$ 1.80

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

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

(3) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the years ended December 31, 2011, 2010 and 2009. Including the effect of this subordination, the average realized gas sales price was $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, 2011, 2010 and 2009, respectively.

(4) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our investment partnerships for the years ended December 31, 2011, 2010 and 2009. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.71 per Mcfe ($1.30 per Mcfe for total production costs), $0.83 per Mcfe ($1.54 per Mcfe for total production costs), and $0.95 per Mcfe ($1.66 per Mcfe for total production costs) for the years ended December 31, 2011, 2010 and 2009, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $0.75 per Mcfe ($1.30 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, 2011, 2010 and 2009, respectively.

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 $15.4 million for the year ended December 31, 2011, a decrease of $6.6 million from $22.0 million for the year ended December 31, 2010. This decrease was principally due to a $3.8 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 $1.3 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 associated with our proportionate share of lease operating expenses associated with our revenue that was subordinated to the investor partners 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. New Albany/Antrim production costs were $1.5 million for the year ended December 31, 2011, an increase of $0.2 million from $1.3 million for the comparable prior year period. This increase was primarily attributable to a $0.1 million increase for maintenance and repair expense and a $0.1 million increase associated with parts, materials and other costs associated with our increased natural gas production in New Albany/Antrim.

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009. Total natural gas revenues were $75.6 million for the year ended December 31, 2010, a decrease of $24.9 million from $100.5 million for the year ended December 31, 2009. This decrease consisted of a $7.8 million decrease attributable to lower natural gas production volumes, a $6.0 million decrease attributable to lower realized natural gas prices and an $11.1 million increase in gas revenues subordinated to the investor partners within our investment partnerships for the year ended December 31, 2010 compared with the prior year. Total oil and natural gas liquids revenues were $17.4 million for the year ended December 31, 2010, an increase of $4.9 million from $12.5 million for the year ended December 31, 2009. This increase resulted from a $5.7 million increase from the sale of natural gas liquids and a $0.8 million increase attributable to higher average oil and natural gas liquids realized prices, partially offset by a $1.6 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 increase in gas revenues subordinated to the investor partners within our investment partnerships was primarily the result of an increase in our natural gas revenues that qualified for subordination to the investor partners within our investment partnerships, partially offset by an overall decrease in our realized natural gas revenues between the periods.

Appalachia production costs were $22.0 million for the year ended December 31, 2010, a decrease of $3.0 million from $25.0 million for the year ended December 31, 2009. This decrease was principally due a $4.1 million increase associated with our proportionate share of lease operating expenses associated with our revenue that was subordinated to the investor partners within our investment partnerships, partially offset by an increase of $1.1 million associated with labor, maintenance expenses and other costs associated with the growth of our operations. New Albany/Antrim production costs were $1.3 million for the year ended December 31, 2010, an increase of $0.8 million from $0.5 million for the prior year. This increase was primarily attributable to an increase in labor, maintenance and compression station expenses associated with the growth of our operations.

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, 2011, 2010 and 2009. There were no exploratory wells drilled during the years ended December 31, 2011, 2010 and 2009:

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	Years Ended December 31,		
	2011	2010	2009
Drilling partnership investor capital:			
Raised	$ 141,929	$ 149,342	$ 353,444
Deployed	$ 135,283	$ 206,802	$ 372,045
Gross partnership wells drilled:			
Appalachia	22	22	174
New Albany/Antrim		66	93
Niobrara	138	29	
Total	160	117	267
Net partnership wells drilled:			
Appalachia	19	21	159
New Albany/Antrim		58	84
Niobrara	138	29	
Total	157	108	243

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,		
	2011	2010	2009
Average construction and completion:			
Revenue per well	$ 886	$ 1,600	$ 1,531
Cost per well	757	1,356	1,299
Gross profit per well	$ 129	$ 244	$ 232
Gross profit margin	$ 19,653	$ 31,555	$ 56,499
Partnership net wells associated with revenue recognized[(1)]:			
Appalachia	21	44	166
New Albany/Antrim	3	63	77
Niobrara	129	22	
	153	129	243

(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, 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. 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. 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.

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009. Well construction and completion segment margin was $31.6 million for the year ended December 31, 2010, a decrease of $24.9 million from $56.5 million for the year ended December 31, 2009. This decrease was due to a $26.4 million decrease associated with a decrease in the number of wells recognized for revenue within the investment partnerships, partially offset by a $1.5 million increase associated with higher gross profit per well. The decrease in the number of wells recognized for revenue was the result of the cancellation of our Fall 2010 drilling program, as discussed above.

Our combined balance sheet at December 31, 2011 includes $71.7 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 combined statements of operations. We expect to recognize this amount as revenue during 2012.

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.

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. Typically, we receive a lower administration and oversight fee related to the Niobrara formation wells we have drilled within the drilling partnerships as compared to the Marcellus Shale and New Albany/Antrim Shale wells. 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.

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009. Administration and oversight fee revenues were $9.7 million for the year ended December 31, 2010, a decrease of $5.9 million from $15.6 million for the year ended December 31, 2009. This decrease was primarily due to a decrease in the number of wells drilled during the current year in comparison to the prior year resulting from the cancellation of our Fall 2010 drilling program, as discussed above.

Well Services

Well service revenue and expenses represent the monthly operating fees we charge and the work our service company performs 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, 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.

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009. Well services revenues were $21.0 million for the year ended December 31, 2010, an increase of $3.1 million from $17.9 million for the year ended December 31, 2009. Well services expenses were $10.8 million for the year ended December 31, 2010, an increase of $1.5 million from $9.3 million for the year ended December 31, 2009. These increases were primarily attributable to a temporary increase in the quantity and scope of ongoing maintenance projects and an increase in the number of producing wells.

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. The gathering fees charged to our investment partnership wells generally range from $0.35 per Mcf to the amount of the competitive gathering fee, currently defined as 13% of the gross sales price of the natural gas. In general, pursuant to gathering agreements we have with a third-party gathering system which gathers the majority of our natural gas, we must also pay an additional amount equal to the excess of the gathering fees collected from the investment partnerships up to an amount equal to approximately 16% of the realized natural gas sales price (adjusted for the settlement of natural gas derivative instruments). However, in most of our direct investment partnerships, we collect a gathering fee of 13% of the realized natural gas sales price per the respective partnership agreement. 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 investment partnerships by approximately 3%.

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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.

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009. Our net gathering and processing expense for the year ended December 31, 2010 was $6.1 million compared with $6.4 million for the year ended December 31, 2009. This favorable decrease was principally due to lower natural gas prices as compared with the prior year period, partially offset by an increase in gathering expenses in the Appalachian Basin resulting from a full year of our third-party gathering system agreement formed in June 2009, whereby our gathering expenses generally exceeded the revenues collected from the investment partnerships by approximately 3%.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

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 $1.8 million of syndication expenses related to the cancellation of our Fall 2010 drilling program and $14.3 million increase of other salary and wages expense and other activities.

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009. General and administrative expenses were $11.4 million for the year ended December 31, 2010 compared with $15.8 million for the year ended December 31, 2009. The $4.4 million decrease was principally due to a decrease in our syndication expenses related to the cancellation of our Fall 2010 drilling program.

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization decreased to $31.9 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. Total depreciation, depletion and amortization decreased to $40.8 million for the year ended December 31, 2010 compared with $43.7 million for the comparable prior year period primarily due to a $3.4 million decrease in our depletion expense.

The following table presents our depletion expense per Mcfe for our operations for the respective periods:

	Years Ended December 31,		
	2011	**2010**	**2009**
Depreciation, depletion and amortization:			
Depletion expense	$ 27,430	$ 36,668	$ 40,067
Depreciation and amortization expense	4,508	4,090	3,645
	$ 31,938	$ 40,758	$ 43,712
Depletion expense (in thousands):			
Total	$ 27,430	$ 36,668	$ 40,067
Depletion expense as a percentage of gas and oil production revenue	41%	39%	35%
Depletion per Mcfe	$ 2.09	$ 2.44	$ 2.63

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, 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.

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For the year ended December 31, 2010, depletion expense decreased $3.4 million to $36.7 million compared with $40.1 million for the year ended December 31, 2009. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 39% for the year ended December 31, 2010, compared with 35% for the year ended December 31, 2009. Depletion expense per Mcfe was $2.44 for the year ended December 31, 2010, a decrease of $0.19 per Mcfe from $2.63 for the year ended December 31, 2009. Depletion expense decreased between periods principally due to an overall decrease in production volumes combined with the $156.4 million impairment of our Upper Devonian Shale field recorded during the three months ended December 31, 2009.

Asset Impairment

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 during the fourth quarter of 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.

During the year ended December 31, 2009, we recognized $156.4 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 Upper Devonian 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, 2009. The estimate of fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices.

Gain (Loss) on Asset Sales

During the year ended December 31, 2011, we recognized a $0.1 million gain on asset sales, compared with a $2.9 million loss on asset sales during the year ended December 31, 2010. The $2.9 million loss on asset sales 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 investment partnerships, and borrowings under our credit facility. Our primary cash requirements, in addition to normal operating expenses, are for debt service and capital expenditures. 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 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.

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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 long-lived 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 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources 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.

Cash Flows Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

Net cash provided by operating activities of $60.6 million for the year ended December 31, 2010 represented an unfavorable movement of $131.6 million from net cash provided by operating activities of $192.2 million for the comparable prior year period. The $131.6 million unfavorable movement in net cash provided by operating activities was primarily due to a $92.5 million unfavorable movement in working capital and a $39.1 million unfavorable movement in net income excluding non-cash items. The $92.5 million unfavorable movement in working capital was principally due to a $107.3 million unfavorable movement in accrued well drilling and completion costs, accounts payable and other accrued liabilities, which was primarily due to an increase in payments for well costs for drilling partnership program wells during the year ended December 31, 2010, which were principally funded with drilling partnership capital raised during the year ended December 31, 2009. In addition, the unfavorable movement in working capital was impacted by a $38.9 million unfavorable movement in liabilities associated with drilling contracts, which consisted of a $204.1 million decrease in drilling partnership capital raised between periods and was partially offset by a decrease in drilling partnership capital deployed of $165.1 million. These amounts were partially offset by a $49.5 million favorable movement in subscriptions receivable from drilling partnerships due primarily to the collection of $46.9 million receivable that was outstanding at December 31, 2009 during the year ended December 31, 2010. Net cash provided by operating activities for the year ended December 31, 2010 also included $103.7 million in net income excluding non-cash items, which represented a $39.1 million unfavorable movement over the comparable prior year period. The $39.1 million unfavorable movement in net income excluding non-cash items included a $105.7 million decrease in non-cash charges related to asset impairment, partially offset by a $63.6 million increase in net income and a $3.0 favorable movement in non-cash gain on derivatives.

Net cash used in investing activities of $92.4 million for the year ended December 31, 2010 represented a favorable movement of $6.0 million from net cash used in investing activities of $98.4 million for the comparable prior year period. This favorable movement was principally due to a $5.7 million favorable movement in capital expenditures. See further discussion of capital expenditures under Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Requirements .

Net cash provided by financing activities of $31.8 million for the year ended December 31, 2010 represented a favorable movement of $125.6 million from net cash used in financing activities of $93.8 million for the comparable prior year period. This movement was principally due to a change in the net investment received from AEI.

Capital Requirements

Our capital requirements consist primarily of:

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

expansion capital expenditures capital expenditures we make to increase our current levels of production 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,		
	2011	2010	2009
Atlas Energy			
Maintenance capital expenditures	$ 9,833	$	$
Expansion capital expenditures	37,491	93,608	99,302
Total	$ 47,324	$ 93,608	$ 99,302

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. 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.

During the year ended December 31, 2010, we had $93.6 million of capital expenditures compared with $99.3 million for the year ended December 31, 2009. The decrease was principally due to a $16.0 million decrease in investments in the investment partnerships, which were $73.4 million for the year ended December 31, 2010 compared with $89.4 million for the prior year, partially offset by a $7.3 million increase in gathering and processing costs, which were $17.2 million for the year ended December 31, 2010 compared with $9.9 million for the prior year. The decrease in investments in the investment partnerships was the result of the cancellation of the Fall 2010 drilling program, while the increase in gathering and processing costs was related to the expansion of our compression facilities associated with the wells drilled during the year ended December 31, 2009.

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. For 2012, we estimate our total capital expenditures, excluding acquisitions, will be approximately $103.3 million related to our natural gas and oil program. This estimate is under continuous review and is subject to ongoing adjustment. We expect to fund these capital expenditures primarily with cash flow from operations and capital raised through our investment partnerships.

OFF BALANCE SHEET ARRANGEMENTS

As of December 31, 2011, Atlas Energy s off-balance sheet arrangements were limited to their letters of credit outstanding of $0.8 million, which were transferred to us on March 5, 2012 (see Subsequent Events).

CASH DISTRIBUTIONS

The board of directors of our general partner has adopted a cash distribution policy, pursuant to our partnership agreement, which requires that we distribute all of our available cash quarterly to our limited partners within 50 days following the end of each calendar quarter in accordance with their respective percentage interests. Under our partnership agreement, available cash is defined to generally mean, for each fiscal quarter, cash generated from our business in excess of the amount of cash reserves established by our general partner to, among other things:

provide for the proper conduct of our business;

comply with applicable law, any of our debt instruments or other agreements; or

provide funds for distributions to our unitholders for any one or more of the next four quarters.

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These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When our general partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level. Our distributions to limited partners are not cumulative. Consequently, if distributions on our common units are not paid with respect to any fiscal quarter, our unitholders are not entitled to receive such payments in the future.

Cash Distribution Policy: Our partnership agreement requires that we distribute 100% of available cash to our common unitholders and general partner, our wholly-owned subsidiary, 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, 2011 (in thousands):

		Payments Due By Period			
Contractual cash obligations:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Operating leases	$ 10,041	$ 1,815	$ 2,550	$ 2,056	$ 3,620
Total contractual cash obligations	$ 10,041	$ 1,815	$ 2,550	$ 2,056	$ 3,620

		Amount of Commitment Expiration Per Period			
Other commercial commitments:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Other commercial commitments[1]	$ 4,150	$ 4,150	$	$	$
Total commercial commitments	$ 4,150	$ 4,150	$	$	$

(1) Our other commercial commitments include our share of capital contributions associated with the funds raised during our Fall 2011 drilling program. We do not have delivery commitments for fixed and determinable quantities of natural gas or oil in any future periods under existing contracts or agreements.

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 Regulations). 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 and their 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 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.

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 combined financial statements included in Item 8: Financial Statements and Supplementary Data . 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 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. 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.

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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 its 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. During the year ended December 31, 2009, we recorded $156.4 million of asset impairment related to gas and oil properties within property, plant and equipment on our combined balance sheet for its shallow natural gas wells in the Upper Devonian Shale. These impairments related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair value at December 31, 2011, 2010 and 2009. 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.

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, 2011, 2010 and 2009.

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 (ARO s) that are defined as Level 3. Estimates of the fair value of ARO s 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.

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. Any significant variance in these assumptions 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.

Asset Retirement Obligations

On an annual basis, we estimate the cost of future dismantlement, restoration, reclamation and abandonment of our operating assets. We and our subsidiaries also estimate the salvage value of equipment recoverable upon abandonment. As

of December 31, 2011 and 2010, the estimate of salvage values was greater than or equal to our estimate of the costs of future dismantlement, restoration, reclamation and abandonment. Projecting future retirement cost estimates is difficult as it involves the estimation of many variables such as economic recoveries of reserves, future labor and equipment rates, future inflation rates and our subsidiaries credit adjusted risk free rate. To the extent future revisions to these assumptions impact the fair value of our existing asset retirement obligation, a corresponding adjustment is made to our gas and oil properties and other property, plant and equipment. A decrease in salvage values or an increase in dismantlement, restoration, reclamation and abandonment costs from those we have estimated, or changes in their estimates or costs, could reduce our gross profit from operations.

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 natural gas and oil prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of the market risk sensitive instruments were entered into for purposes other than trading.

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2011. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our and our subsidiaries 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 and interest-rate 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.

Commodity Price Risk. Our market risk exposure to commodities is due to the fluctuations in the price of natural gas, natural gas liquids and oil and the impact those price movements have on the financial results of us. To limit our exposure to changing natural gas, oil, and natural gas liquids prices, we use financial derivative instruments for a portion of our future natural gas and oil production. We enter into financial swap and option instruments to hedge forecasted sales against the variability in expected future cash flows attributable to changes in market prices. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, natural gas liquids and oil 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 natural gas, natural gas liquids and oil at a fixed price for the relevant period.

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in the average price of natural gas, natural gas liquids and oil would result in a change to our combined operating income from continuing operations attributable to common limited partners for the twelve-month period ending December 31, 2012 of approximately \$2.1 million, net of non-controlling interests.

Realized pricing of our natural gas, oil, and natural gas liquids production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas, oil and natural gas liquids 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 natural gas liquids prices, we enter into natural gas and oil swap 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 futures contracts with qualified counterparties. 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

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Texas Intermediate (WTI) index. Natural gas liquids contracts are based on an OPIS Mt. Belvieu index. These contracts have qualified and been designated as cash flow hedges and been recorded at their fair values.

At December 31, 2011, 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)]
2012	5,520,000	$	5.000
2013	3,120,000	$	5.288
2014	2,880,000	$	5.590
2015	2,880,000	$	5.861

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (mmbtu)[(1)]		Average Floor and Cap (per mmbtu) [(1)]
2012	Puts purchased	4,320,000	$	4.074
2012	Calls sold	4,320,000	$	5.279
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	3,840,000	$	4.296
2015	Calls sold	3,840,000	$	5.233

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl) [(1)]		Average Floor and Cap (per Bbl) [(1)]
2012	Puts purchased	60,000	$	90.000
2012	Calls sold	60,000	$	117.912
2013	Puts purchased	60,000	$	90.000
2013	Calls sold	60,000	$	116.396
2014	Puts purchased	24,000	$	80.000
2014	Calls sold	24,000	$	121.250
2015	Puts purchased	24,000	$	80.000

2015	Calls sold	24,000	$ 120.750

(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 balance sheet of Atlas Resource Partners, L.P. (a Delaware Limited Partnership) (the Partnership) as of December 31, 2011. This financial statement is the responsibility of the Partnership s management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statement. 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statement referred to above presents fairly, in all material respects, the financial position of Atlas Resource Partners, L.P. as of December 31, 2011, 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, 2011, 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 March 29, 2012 expressed an adverse opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

March 29, 2012

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ATLAS RESOURCE PARTNERS, L.P.

BALANCE SHEET

		December 31, 2011
PARTNER S CAPITAL		
Partner s Capital:		
Partner s capital	$	1,000
Capital contribution receivable		(1,000)
Total partner s capital	$	

See accompanying note to the balance sheet.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO BALANCE SHEET

December 31, 2011

NOTE 1 BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the Partnership) is a Delaware limited partnership formed in October 2011. At December 31, 2011, we were wholly-owned by Atlas Energy, L.P. (Atlas Energy), a publicly-traded master limited partnership (NYSE: ATLS). In February 2012, the General Partner s board of directors of Atlas Energy (the Board) approved the distribution of approximately 5.24 million of the Partnership s common units, which was distributed on March 13, 2012 to Atlas Energy s unitholders using a ratio of 0.1021 of the Partnership s limited partner units for each of Atlas Energy s common units owned on the record date of February 28, 2012. The distribution of its limited partner units will represent an approximate 19.6% limited partner interest. Subsequent to the distribution, Atlas Energy will own a 2% general partner interest, all of the Partnership s incentive distribution rights and common units representing an approximate 78.4% limited partner interest in the Partnership. Beginning on March 14, 2012, the Partnership will be a publicly-traded master limited partnership (NYSE: ARP).

In February 2012, the Board also approved the transfer to the Partnership of the Atlas Energy E&P Operations (the Company) from Atlas Energy. As Atlas Energy did not contribute its ownership interest in the Atlas Energy E&P Operations to the Partnership until after the completion of the historical periods covered by this Form 10-K, the Partnership has provided its stand-alone financial statements within this section. The combined financial statements of the Atlas Energy E&P Operations have been included elsewhere within this Form 10-K.

NOTE 2 SUBSEQUENT EVENTS

Acquisition of Assets from Carrizo Oil & Gas, Inc. On March 15, 2012, the Partnership entered into a definitive agreement with Carrizo Oil & Gas, Inc. to purchase certain assets for $190 million in cash (the Acquisition). The purchase price is subject to certain post-closing adjustments based on, among other things, environmental and title defects, if any. The assets being acquired include interests in approximately 200 natural gas wells producing from the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas, and related proved undeveloped acres as well as gathering pipelines and associated gathering facilities that service certain of the acquired wells. The closing of the Acquisition is expected to occur on or before April 30, 2012, and is subject to customary closing conditions.

To partially fund the Acquisition, on March 15, 2012 the Partnership executed a unit purchase agreement with several purchasers for the sale of 6.0 million of its common units at a negotiated purchase price per unit of $20.00, for anticipated gross proceeds of $120.0 million. The issuance of the common units is subject to customary closing conditions, including the closing of the Acquisition.

On March 15, 2012, the Partnership executed a commitment letter with Wells Fargo Bank, N.A., as administrative agent for the lenders under the credit facility, for the purpose of amending the facility to increase the borrowing base to $250.0 million and the maximum lender commitment to $500.0 million. The closing of the amendment to the facility is expected to occur on or before April 30, 2012, and is subject to customary closing conditions, including the closing of the Acquisition.

Credit Facility. On March 5, 2012, Atlas Energy s credit facility was amended and restated so that it assigned, and the Partnership assumed, Atlas Energy s rights, privileges and obligations under the credit facility. Subject to the March 15, 2012 commitment letter described above, the credit facility continues to have maximum lender commitments of $300 million, a borrowing base of $138 million and matures in March 2016. Up to $20.0 million of the credit facility may be in the form of standby letters of credit. The Partnership s obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by substantially all of the Partnership s subsidiaries. Borrowings under the credit facility bear interest, at the Partnership s election, at either LIBOR plus an applicable margin between 2.00% and 3.25% 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%. The Partnership is also required to pay a fee of 0.5% per annum on the unused portion of the borrowing base, which is included within interest expense on its combined statements of operations.

The credit agreement contains customary covenants that limit the Partnership s ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The credit agreement also requires the Partnership to maintain a ratio

of Total Funded Debt (as defined in the credit agreement) to four quarters (actual or annualized, as applicable) of EBITDA (as defined in the credit agreement) not greater than 3.75 to 1.0 as of the last day of any fiscal quarter, a ratio of current assets (as defined in the credit agreement) to current liabilities (as defined in the credit agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter, and a ratio of four quarters (actual or annualized, as applicable) of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.5 to 1.0 as of the last day of any fiscal quarter.

Secured Hedge Facility. On March 5, 2012, the Partnership entered into a secured hedge facility agreement with a syndicate of banks under which certain recently formed investment partnerships are eligible to participate in the Partnership s hedging arrangements. The secured hedge facility agreement contains covenants that limit each of the participating investment 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.

Formation and distribution of Atlas Resource Partners, L.P. In February 2012, the board of directors of the general partner of Atlas Energy approved the distribution of approximately 5.24 million of the Partnership s common units, which were distributed on March 13, 2012 to Atlas Energy s unitholders using a ratio of 0.1021 Partnership limited partner units for each Atlas Energy common unit owned on the record date of February 28, 2012. In connection with the distribution, the board of directors of the general partner of Atlas Energy also approved the transfer to the Partnership of Atlas Energy s E&P Operations. The distribution of the Partnership s limited partner units represented approximately 19.6% of its outstanding limited partner interests. Subsequent to the distribution, Atlas Energy owns a 2% general partner interest, all of the incentive distribution rights and common units representing an approximate 78.4% limited partner interest in the Partnership. The Partnership s common units began trading regular-way under the ticker symbol ARP on the New York Stock Exchange on March 14, 2012.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Resource Partners, L.P.

We have audited the accompanying combined balance sheets of Atlas Energy E&P Operations (See Note 1) (the Company) as of December 31, 2011 and 2010, and the related combined statements of operations, comprehensive income (loss), equity and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 combined financial statements referred to above present fairly, in all material respects, the financial position of Atlas Energy E&P Operations as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

March 29, 2012

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ATLAS ENERGY E&P OPERATIONS

COMBINED BALANCE SHEETS

(in thousands)

ASSETS	December 31, 2011	December 31, 2010
Current assets:		
Cash and cash equivalents	$ 54,708	$
Accounts receivable	19,319	20,800
Current portion of derivative asset	13,801	36,621
Subscriptions receivable	34,455	
Prepaid expenses and other	7,677	8,585
Total current assets	129,960	66,006
Property, plant and equipment, net	520,883	508,484
Intangible assets, net	1,501	2,164
Goodwill, net	31,784	31,784
Long-term derivative asset	16,128	36,125
Long-term derivative receivable from Drilling Partnerships		4,669
Other assets, net	857	
	$ 701,113	$ 649,232
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 36,731	$ 45,957
Liabilities associated with drilling contracts	71,719	65,072
Current portion of derivative liability		353
Current portion of derivative payable to Drilling Partnerships	20,900	30,797
Accrued well drilling and completion costs	17,585	30,126
Accrued liabilities	35,952	11,283
Total current liabilities	182,887	183,588
Long-term derivative liability		6,293
Long-term derivative payable to Drilling Partnerships	15,272	34,796
Asset retirement obligation	45,779	42,673
Commitments and contingencies		
Equity:		
Equity	427,246	376,567
Accumulated other comprehensive income	29,929	5,315
Total equity	457,175	381,882
	$ 701,113	$ 649,232

See accompanying notes to combined financial statements.

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ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF OPERATIONS

(in thousands)

	00000000000	00000000000	00000000000
		Years Ended December 31,	
	2011	**2010**	**2009**
Revenues:			
Gas and oil production	$ 66,979	$ 93,050	$ 112,979
Well construction and completion	135,283	206,802	372,045
Gathering and processing	17,746	14,087	18,839
Administration and oversight	7,741	9,716	15,554
Well services	19,803	20,994	17,859
Other, net	(30)		
Total revenues	247,522	344,649	537,276
Costs and expenses:			
Gas and oil production	17,100	23,323	25,557
Well construction and completion	115,630	175,247	315,546
Gathering and processing	20,842	20,221	25,269
Well services	8,738	10,822	9,330
General and administrative	27,536	11,381	15,832
Depreciation, depletion and amortization	30,869	40,758	43,712
Long-lived asset impairment	6,995	50,669	156,359
Total costs and expenses	227,710	332,421	591,605
Operating income (loss)	19,812	12,228	(54,329)
Loss on asset sales	87	(2,947)	
Net income (loss)	$ 19,899	$ 9,281	$ (54,329)

See accompanying notes to combined financial statements.

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ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	00000000000	00000000000	00000000000
	Years Ended December 31,		
	2011	**2010**	**2009**
Net income (loss)	$ 19,899	$ 9,281	$ (54,329)
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as cash flow hedges	35,156	16,542	27,846
Less: reclassification adjustment for realized gains in net income (loss)	(10,542)	(27,364)	(43,745)
Total other comprehensive income (loss)	24,614	(10,822)	(15,899)
Comprehensive income (loss) attributable to owner	$ 44,513	$ (1,541)	$ (70,228)

See accompanying notes to combined financial statements.

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ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF EQUITY

(in thousands)

	00000000000 Equity	00000000000 Accumulated Other Comprehensive Income (Loss)	00000000000 Total
Balance at January 1, 2009	$ 483,586	$ 32,036	$ 515,622
Net distribution to Atlas Energy, Inc.	(93,808)		(93,808)
Other comprehensive loss		(15,899)	(15,899)
Net loss	(54,329)		(54,329)
Balance at December 31, 2009	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

See accompanying notes to combined financial statements.

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ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF CASH FLOWS

(in thousands)

	000000000000	000000000000	000000000000
		Years Ended December 31,	
	2011	**2010**	**2009**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 19,899	$ 9,281	$ (54,329)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	30,869	40,758	43,712
Long-lived asset impairment	6,995	50,669	156,359
Non-cash (gain) loss on derivative value, net	36,171		(3,022)
(Gain) loss on asset sales	(87)	2,947	
Changes in operating assets and liabilities:			
Accounts receivable and prepaid expenses and other	(32,203)	53,751	103
Accounts payable and accrued liabilities	9,793	(96,820)	49,378
Net cash provided by operating activities	71,437	60,586	192,201
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(47,324)	(93,608)	(99,302)
Other	(185)	1,185	909
Net cash used in investing activities	(47,509)	(92,423)	(98,393)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net investment received from Atlas Energy, Inc. (see Note 3)	30,780	31,837	
Net distribution to Atlas Energy, Inc. (see Note 3)			(93,808)
Net cash provided by (used in) financing activities	30,780	31,837	(93,808)
Net change in cash and cash equivalents	54,708		
Cash and cash equivalents, beginning of year			
Cash and cash equivalents, end of year	$ 54,708	$	$

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

NOTES TO COMBINED FINANCIAL STATEMENTS

NOTE 1 BASIS OF PRESENTATION

The Atlas Energy E&P Operations (the Company) is an independent developer and producer of natural gas and oil, with operations in the Appalachian Basin, Illinois Basin and the Rocky Mountain region. We sponsor and manage tax-advantaged investment partnerships, in which we co-invest, to finance a portion of our natural gas and oil production activities.

On February 17, 2011, Atlas Energy acquired certain assets and liabilities (the Transferred Business) from Atlas Energy, Inc. (AEI), the former owner of Atlas Energy s general partner (see Note 3). These assets principally included the following exploration and production assets:

- AEI s investment management business, which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which the Company funds 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 the Company is a developer and producer.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Combination

The Company s combined balance sheets at December 31, 2011 and 2010 and the related combined statements of operations for the years ended December 31, 2011, 2010 and 2009 were derived from the separate records maintained by Atlas Energy and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all the various entities comprising the Company, Atlas Energy s net investment in the Company 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 combined balance sheets and related combined statements of operations. Such estimates included allocations made from the historical accounting records of Atlas Energy, based on management s best estimates, in order to derive the financial statements of the Company. Actual balances and results could be different from those estimates. Transactions between the Company and other Atlas Energy operations have been identified in the combined statements as transactions between affiliates (see Note 3).

In accordance with prevailing accounting literature, management of Atlas Energy determined that the acquisition of the Transferred Business on February 17, 2011 constituted a transaction between entities under common control (see Note 3). In comparison to the purchase 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 on the Company s combined balance sheet. Also, in comparison to the purchase method of accounting, whereby the results of operations and the financial position of the Transferred Business would have been included in the Company s 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, the Company reflected the impact of the acquisition of the Transferred Business on its 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 (See Note 3);

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

Adjusted the presentation of its 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. 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 aggregation of assets and liabilities now defined as the Predecessor. The Company has reviewed AEI s general and administrative expense allocation methodology, which is based on the relative total assets of AEI and the Transferred Business, for the Transferred Business historical financial statements prior to the date of acquisition and believe the methodology is reasonable and reflects the approximate general and administrative costs of its underlying business segments.

In accordance with established practice in the oil and gas industry, the Company s financial statements include its pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the energy partnerships in which the Company has an interest (the Drilling Partnerships). Such interests typically range from 20% to 41%. The Company s financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, the Company calculates these items specific to its own economics as further explained under the heading Property, Plant and Equipment elsewhere within this note.

Use of Estimates

The preparation of the Company s combined financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Company s combined financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Company s combined financial statements are based on a number of significant estimates, including the revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. Such estimates included estimated allocations made from the historical accounting records of AEI in order to derive the historical period financial statements of the Company. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months financial results were recorded using estimated volumes and contract market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented for the year ended December 31, 2011, 2010 and 2009 represent actual results in all material respects (see *Revenue Recognition* accounting policy for further description).

Cash Equivalents

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

Receivables

Accounts receivable on the combined balance sheets consist solely of the trade accounts receivable associated with the Company s operations. In evaluating the realizability of its accounts receivable, the Company s management performs ongoing credit evaluations of its customers and adjust credit limits based upon payment history and the customer s current creditworthiness, as determined by management s review of the Company s customers credit information. The Company extends credit on sales on an unsecured basis to many of its customers. At December 31, 2011 and 2010, the Company had recorded no allowance for uncollectible accounts receivable on its combined balance sheets.

Inventory

The Company had $3.9 million and $5.9 million of inventory at December 31, 2011 and 2010, respectively, which were included within prepaid expenses and other current assets on the Company s combined balance sheets. The Company values inventories at the lower of cost or market. The Company s inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

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Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired (see *Principles of Consolidation and Combination*). Maintenance and repairs are expensed as incurred. Major renewals and improvements that extend the useful lives of property are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset s estimated useful life. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Company s results of operations.

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

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

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

Impairment of Long-Lived Assets

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

The review of the Company s oil and gas properties is done on a field-by-field basis by determining if the historical cost of proved properties less the applicable accumulated depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Company s 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. The Company estimates prices based upon current contracts in place at December 31, 2011, adjusted for basis differentials and market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, the Company s reserve estimates for its investment in the Drilling Partnerships are based on its own assumptions rather than its proportionate share of the limited partnerships reserves. These assumptions include the Company s actual capital contributions, an additional carried interest (generally 5% to 10%), a disproportionate share of salvage value upon plugging of the wells and lower operating and administrative costs.

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

The Company s method of calculating its reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships, which the Company sponsors and owns an interest in but does not control. The Company s reserve quantities include reserves in excess of its proportionate share of reserves in Drilling Partnerships, which the Company may be unable to recover due to the Drilling Partnerships legal structure. The Company may have to pay additional consideration in the future as a well or Drilling Partnership becomes uneconomic under the terms of the Drilling Partnership s agreement in order to recover these excess reserves and to acquire any additional residual interests in the wells held by other partnership investors. The acquisition of any well interest from the Drilling Partnership by the Company is governed under the Drilling Partnership s agreement and in general, must be at fair market value supported by an appraisal of an independent expert selected by the Company.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Company will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. There were no impairments of unproved gas and oil properties recorded by the Company for the years ended December 31, 2011, 2010 and 2009.

During the year ended December 31, 2011, the Company recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment on its combined balance sheet for its shallow natural gas wells in the Niobrara Shale. During the year ended December 31, 2010, the Company recognized $50.7 million of asset impairment related to gas and oil properties within property, plant and equipment, net on its combined balance sheet for its shallow natural gas wells in the Chattanooga and Upper Devonian shales. During the year ended December 31, 2009, the Company recorded $156.4 million of asset impairment related to gas and oil properties within property, plant and equipment, net on its combined balance sheet for its shallow natural gas wells in the Upper Devonian Shale. These impairments related to the carrying amount of these gas and oil properties being in excess of the Company s estimate of their fair value at December 31, 2011, 2010 and 2009. The estimate of the 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.

Intangible Assets

The Company recorded its own intangible assets with finite lives in connection with partnership management and operating contracts acquired through prior consummated acquisitions. The Company amortizes contracts acquired on a declining balance and straight-line method over their respective estimated useful lives.

The following table reflects the components of intangible assets being amortized at December 31, 2011 and 2010 (in thousands):

	December 31,		**Estimated Useful Lives In Years**
	2011	**2010**	
Gross Carrying Amount	$ 14,344	$ 14,344	1 13
Accumulated Amortization	(12,843)	(12,180)	
Net Carrying Amount	$ 1,501	$ 2,164	

Amortization expense on intangible assets was $0.7 million, $0.7 million and $1.0 million for the years ended December 31 2011, 2010 and 2009, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2012 $0.2 million; 2013 $0.2 million; 2014 $0.1 million; 2015 $0.1 million; and 2016 $0.1 million.

Goodwill

At December 31, 2011, and 2010, the Company had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions. There were no changes in the carrying amount of goodwill for the years ended December 31, 2011, 2010 and 2009.

Management tests the Company s goodwill for impairment at each year end by comparing its reporting unit estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Company s management must apply judgment in determining the estimated fair value of these reporting units. The Company s management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Company s assets. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Company s market capitalization. The observed market prices of individual trades of an entity s equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Company s, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Company s management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Company s industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Company s industry to determine whether those valuations appear reasonable in management s judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise. During the years ended December 31, 2011, 2010 and 2009, no goodwill impairments were recognized by the Company.

Derivative Instruments

The Company enters into certain financial contracts to manage their exposure to movement in commodity prices and interest rates (see Note 6). The derivative instruments recorded in the combined balance sheets were measured as either an asset or liability at fair value. Changes in a derivative instrument s fair value are recognized currently in the Company s combined statements of operations unless specific hedge accounting criteria were met.

Accounts Payable

Accounts payable was determined based on an allocation of the amounts related to the operations of the Company.

Asset Retirement Obligations

Pursuant to prevailing accounting literature, the Company recognizes an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities (see Note 5). The Company recognizes a liability for future asset retirement obligations in the current period if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Company is required to consider estimated salvage value in the calculation of depreciation, depletion and amortization.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. Management has established procedures for the ongoing evaluation of the Company s operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. The Company maintains insurance, which may cover in whole or in part certain environmental expenditures. At December 31, 2011 and 2010, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Concentration of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist principally of periodic temporary investments of cash and cash equivalents. The Company places its temporary cash investments in high-quality short-term money market instruments and deposits with high-quality financial institutions and brokerage firms. At December 31, 2011, the Company had $64.9 million in deposits at various banks, of which $59.1 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments to date.

The Company sells natural gas, crude oil and natural gas liquids (NGLs) under contracts to various purchasers in the normal course of business. For the year ended December 31, 2011, the Company had three customers that individually accounted for approximately 17%, 14% and 10%, respectively, of the Company s natural gas and oil combined revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2010, the Company had four customers that individually accounted for 13%, 12%, 12% and 11%, respectively, of the Company s natural gas and oil combined revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2009, the Company had one customer that individually accounted for approximately 16% of the Company s natural gas and oil combined revenues, excluding the impact of all financial derivative activity.

Revenue Recognition

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

The Company generally sells natural gas, crude oil and NGLs at prevailing market prices. Generally, the Company s sales contracts are based on pricing provisions that are tied to a market index, with certain fixed adjustments based on proximity to gathering and transmission lines and the quality of its natural gas. Generally, the market index is fixed 2 business days prior to the commencement of the production month. Revenue and the related accounts receivable are recognized when produced quantities are delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Revenues from the production of natural gas and crude oil, in which the Company has an interest with other producers, are recognized on the basis of its percentage ownership of the working interest and/or overriding royalty.

The Company accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, crude oil and condensate and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Company s records and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see *Use of Estimates* accounting policy for further description). The Company had unbilled revenues at December 31, 2011 and 2010 of $12.6 million and $20.8 million, respectively, which were included in accounts receivable within the Company s combined balance sheets.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under accounting principles generally accepted in the United States, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as other comprehensive income (loss) and for the Company includes changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges.

Recently Adopted Accounting Standards

In December 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2010-29, *Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations* (Update 2010-29). The amendments in Update 2010-29 affect any public entity, as defined by Topic 805 *Business Combinations,* that enters into business combinations that are material on an individual or aggregate basis. Update 2010-29

specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Update 2010-29 also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The Company applied the requirements of Update 2010-29 upon its adoption on January 1, 2011, and it did not have a material impact on its financial position, results of operations or related disclosures.

In December 2010, the FASB issued Accounting Standards Update 2010-28*, Intangibles Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts* (Update 2010-28). Update 2010-28 modifies Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist in between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The Company applied the requirements of Update 2010-28 upon its adoption on January 1, 2011, and it did not have a material impact on its financial position, results of operations or related disclosures.

Recently Issued Accounting Standards

In December 2011, the FASB issued Accounting Standards Update 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* (Update 2011-12). The amendments in this update effectively defer implementation of changes made in Update 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income* (Update 2011-05), related to the presentation of reclassification adjustments out of accumulated other comprehensive income. Under Update 2011-05 which was issued by the FASB in June 2011, entities are provided the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with a total net income, each component of other comprehensive income and a total amount for comprehensive income. Update 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders equity. As a result of Update 2011-12, entities are required to disclose reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect prior to Update 2011-05. All other requirements in Update 2011-05 are not affected by Update 2011-12. Update 2011-12 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Accordingly, entities will not be required to comply with presentation requirements of Update 2011-05 related to the disclosure of reclassifications out of accumulated other comprehensive income. The Company will apply the requirements of Update 2011-12 upon its effective date of January 1, 2012, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In December 2011, the FASB issued Accounting Standards Update 2011-11, *Balance Sheet (Topic 210): Disclosure about Offsetting Assets and Liabilities* (Update 2011-11). The amendments in this update require an entity to disclose both gross and net information about both financial and derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the statement of financial position. An entity shall disclose at the end of a reporting period certain quantitative information separately for assets and liabilities that are within the scope of Update 2011-11, as well as provide a description of the rights of setoff associated with an entity s recognized assets and recognized liabilities subject to an enforceable master netting arrangement or similar agreement. Update 2011-11 will be effective for annual reporting periods, and interim periods within those years, beginning on or after January 1, 2013. Upon adoption, the presentation requirements of Update 2011-11 are required to be applied to all comparative periods presented. The Company will apply the requirements of Update 2011-11 upon its effective date of January 1, 2013, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In September 2011, the FASB issued Accounting Standards Update 2011-08, *Intangibles-Goodwill and Other (Topic 350): Testing Goodwill for Impairment* (Update 2011-08). The amendments in Update 2011-08 allow an entity to first assess qualitative factors in determining the necessity of performing the two-step quantitative goodwill impairment test. If, after assessing qualitative factors, an entity determines it is not likely that the fair value of a reporting unit is less than its carrying amount, performing the two-step impairment test is unnecessary. Under the amendments in Update 2011-08, an entity has the option to bypass the qualitative assessment and proceed directly to performing the first step of the two-step impairment test. Update 2011-08 will be effective for fiscal years beginning after December 15, 2011, with early adoption permitted. The Company will apply the requirements of Update 2011-08 upon its effective date of January 1, 2012, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In May 2011, the FASB issued Accounting Standards Update 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (Update 2011-04). The amendments in Update 2011-04 revise the wording used to describe many of the requirements for measuring fair value and for disclosing information about fair value measurements in U.S. GAAP. For many of the amendments, the guidance is not necessarily intended to result in a change in the application of the requirements in Topic 820; rather it is intended to clarify the intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. As a result, Update 2011-04 aims to provide common fair value measurement and disclosure requirements in U.S. GAAP and International Financial Reporting Standards. Update 2011-04 will be effective for interim and annual periods beginning after December 15, 2011. Early adoption by public entities is not permitted. The Company will apply the requirements of Update 2011-04 upon its effective date of January 1, 2012, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

NOTE 3 ATLAS ENERGY ACQUISITION FROM ATLAS ENERGY, INC.

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

- AEI s investment management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which the Company funds a portion of its natural gas and oil well drilling;
- proved reserves located in the Appalachian Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan and the Chattanooga Shale of northeastern Tennessee;
- certain producing natural gas and oil properties, upon which the Company is the developer and producer;

In addition to the exploration and production assets, the Transferred Business also included all of the ownership interests in Atlas Energy GP, LLC, Atlas Energy s general partner and a direct and indirect ownership interest in Lightfoot Capital Partners, LP (Lightfoot LP) and Lightfoot Capital Partners GP, LLC, the general partner of Lightfoot LP (collectively, Lightfoot), entities which incubate new master limited partnerships (MLPs) and invest in existing master limited partnerships.

For the assets acquired and liabilities assumed, Atlas Energy issued approximately 23.4 million of its common limited partner units and paid $30.0 million in cash consideration. Based on Atlas Energy s February 17, 2011 common unit closing price of $15.92, the common units issued to AEI were valued at approximately $372.2 million. In connection with the transaction, Atlas Energy also received $118.7 million with respect to a contractual cash transaction adjustment from AEI related to certain liabilities assumed by Atlas Energy, including certain amounts subject to a reconciliation period following the consummation of the transaction. The reconciliation period was ongoing at December 31, 2011, and certain amounts included within the contractual cash transaction adjustment are in dispute between the parties. The resolution of the disputed amounts could result in Atlas Energy being required to repay a portion of the cash transaction adjustment (see Note 9). Including the cash transaction adjustment, the net book value of the Transferred Business was approximately $522.9 million.

Concurrent with Atlas Energy s acquisition of assets, including the assets and liabilities of the Company, AEI completed its merger with Chevron Corporation (Chevron), whereby AEI became a wholly owned subsidiary of Chevron. Also concurrent with Atlas Energy s acquisition of assets and immediately preceding AEI s merger with Chevron, Atlas Pipeline Partners, L.P. (APL), a publicly-traded limited partnership (NYSE: APL) in which Atlas Energy owns a 2% general partner interest, all of the incentive distribution rights, and an approximate 10.7% common limited partner interest at December 31, 2011, completed its sale to AEI of its 49% non-controlling interest in the Laurel Mountain joint venture (the Laurel Mountain Sale). APL received $409.5 million in cash, including adjustments based on certain capital contributions APL made to and distributions it received from the Laurel Mountain joint venture after January 1, 2011. APL retained the preferred distribution rights under the limited liability company agreement of the Laurel Mountain joint venture entitling APL to receive all payments made under the note receivable issued to Laurel Mountain by Williams Laurel Mountain, LLC in connection with the formation of the Laurel Mountain joint venture.

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In accordance with prevailing accounting literature, management of Atlas Energy determined that the acquisition of the Transferred Business constituted a transaction between entities under common control (see Note 2). As such, Atlas Energy recognized the assets acquired and liabilities assumed at historical carrying value at the date of acquisition, with the difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital on its combined balance sheet. Atlas Energy recognized a non-cash decrease of $261.0 million in partner s capital on its combined balance sheet based on the excess net book value above the value of the consideration paid to AEI. The following table presents the historical carrying value of the assets acquired and liabilities assumed by Atlas Energy, including the effect of cash transaction adjustments, as of February 17, 2011 (in thousands):

Cash	$	153,350
Accounts receivable		18,090
Accounts receivable affiliate		45,682
Prepaid expenses and other		6,955
Total current assets		224,077
Property, plant and equipment, net		516,625
Goodwill		31,784
Intangible assets, net		2,107
Other assets, net		20,416
Total long-term assets		570,932
Total assets acquired	$	795,009
Accounts payable	$	59,202
Net liabilities associated with drilling contracts		47,929
Accrued well completion costs		39,552
Current portion of derivative payable to Drilling Partnerships		25,659
Accrued liabilities		25,283
Total current liabilities		197,625
Long-term derivative payable to Drilling Partnerships		31,719
Asset retirement obligations		42,791
Total long-term liabilities		74,510
Total liabilities assumed	$	272,135
Historical carrying value of net assets acquired	$	522,874

Also in accordance with prevailing accounting literature, Atlas Energy reflected the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which the Transferred Business was acquired and retrospectively adjusted its prior year financial statements to furnish comparative information (see Note 2).

NOTE 4 PROPERTY, PLANT AND EQUIPMENT

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

	December 31,		Estimated
	2011	2010	

					Useful Lives in Years
Natural gas and oil properties:					
Proved properties:					
Leasehold interests	$	61,587	$	46,495	
Pre-development costs		2,540		2,337	
Wells and related equipment		828,780		798,269	
Total proved properties		892,907		847,101	
Unproved properties		43,253		42,520	
Support equipment		9,413		8,138	
Total natural gas and oil properties		945,573		897,759	
Pipelines, processing and compression facilities		32,149		30,072	2 40
Rights of way		84		84	20 40
Land, buildings and improvements		4,822		5,632	3 40
Other		1,180		4,727	3 10
		983,808		938,274	
Less accumulated depreciation, depletion and amortization		(462,925)		(429,790)	
	$	520,883	$	508,484	

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During the year ended December 31, 2011, the Company recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment, net on its combined balance sheet for its shallow natural gas wells in the Niobrara Shale. During the year ended December 31, 2010, the Company recognized $50.7 million of asset impairment related to gas and oil properties within property, plant and equipment, net on its combined balance sheet for its shallow natural gas wells in Chattanooga and Upper Devonian shales. During the year ended December 31, 2009, the Company recognized $156.4 million of asset impairment related to gas and oil properties within property, plant and equipment, net on its combined balance sheet for its shallow natural gas wells in the Upper Devonian Shale. These impairments related to the carrying amount of these gas and oil properties being in excess of the Company s estimate of their fair value at December 31, 2011, 2010 and 2009, respectively. 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.

NOTE 5 ASSET RETIREMENT OBLIGATIONS

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

The estimated liability is based on the Company s historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. The Company has no assets legally restricted for purposes of settling asset retirement obligations. Except for its gas and oil properties, the Company has determined that there are no other material retirement obligations associated with tangible long-lived assets.

A reconciliation of the Company s liability for well plugging and abandonment costs for the periods indicated is as follows (in thousands):

	Years Ended December 31,		
	2011	**2010**	**2009**
Asset retirement obligations, beginning of year	$ 42,673	$ 36,599	$ 33,881
Liabilities incurred	713	472	909
Liabilities settled	(209)	(373)	(248)
Accretion expense	2,602	2,205	2,057
Revisions		3,770	
Asset retirement obligations, end of year	$ 45,779	$ 42,673	$ 36,599

The above accretion expense was included in depreciation, depletion and amortization in the Company s combined statements of operations and the asset retirement obligation liabilities were included within other long-term liabilities in the Company s combined balance sheets.

NOTE 6 DERIVATIVE INSTRUMENTS

The Company uses a number of different derivative instruments, principally swaps, collars and options, in connection with their commodity and interest rate price risk management activities. Management enters into financial instruments to hedge forecasted natural gas and crude oil sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas and crude oil are sold. Under commodity-based swap agreements, the Company receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period.

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

Derivatives are recorded on the Company s combined balance sheets as assets or liabilities at fair value. The Company reflected net derivative assets on its combined balance sheets of $29.9 million and $66.1 million at December 31, 2011 and 2010, respectively. Of the $29.9 million of net gain in accumulated other comprehensive income within equity on the Company s combined balance sheet related to derivatives at December 31, 2011, if the fair values of the instruments remain at current market values, the Company will reclassify $13.8 million of gains to gas and oil production revenue on its combined statement of operations over the next twelve month period as these contracts expire. Aggregate gains of $16.1 million of gas and oil production revenues will be reclassified to the Company s combined statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future price changes.

The following table summarizes the fair value of the Company s own derivative instruments as of December 31, 2011 and 2010, as well as the gain or loss recognized in the consolidated combined statements of operations for effective derivative instruments for the years ended December 31, 2011, 2010 and 2009:

Contract Type	Balance Sheet Location	December 31, 2011	December 31, 2010
Asset Derivatives			
Commodity contracts	Current portion of derivative asset	$ 14,146	$ 36,528
Commodity contracts	Long-term derivative asset	21,485	36,020
		35,631	72,548
Liability Derivatives			
Commodity contracts	Current portion of derivative asset	(345)	(311)
Commodity contracts	Long-term derivative asset	(5,357)	(6,137)
		(5,702)	(6,448)
Total derivatives		$ 29,929	$ 66,100

	Years Ended December 31, 2011	2010	2009
Gain recognized in accumulated OCI	$ 35,156	$ 16,542	$ 27,846
(Gain) reclassified from accumulated OCI into income	$ (10,542)	$ (27,364)	$ (43,745)

The Company enters into natural gas and crude oil future option and collar contracts to achieve more predictable cash flows by hedging its exposure to changes in natural gas prices and oil prices. At any point in time, such contracts may include regulated New York Mercantile Exchange (NYMEX) futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. Crude oil contracts are based on a West Texas Intermediate (WTI) index. These contracts have qualified and been designated as cash flow hedges and recorded at their fair values.

The Company recognized gains of $10.5 million, $27.4 million and $43.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, on settled contracts covering natural gas and oil production for historical periods. These gains are included within gas and oil production revenue in the Company s combined statements of operations. As the underlying prices and terms in the Company s derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the years ended December 31, 2011, 2010 and 2009 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

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Prior to its merger transaction with Chevron on February 17, 2011, AEI monetized all of its derivative instruments, including those related to the future natural gas and oil production of the Transferred Business (see Note 3). AEI also monetized derivative instruments which were specifically related to the future natural gas and oil production of the limited partners of the Drilling Partnerships. Monetization proceeds of $57.4 million related to the amounts hedged on behalf of the Drilling Partnerships limited partners were included within cash and cash equivalents acquired of the Transferred Business at the date of acquisition. The Company has and will continue to allocate the monetization net proceeds received to the Drilling Partnerships limited partners based on their natural gas and oil production generated over the period of the original derivative contracts. At December 31, 2011, the Company recognized a current and long-term derivative payable to Drilling Partnerships of $20.9 million and $15.3 million, respectively, on its combined balance sheets related to the future allocation of the monetization net proceeds.

At December 31, 2011, the Company had the following commodity derivatives:

Natural Gas Fixed Price Swaps

Production Period Ending December 31,	Volumes (mmbtu)(1)	Average Fixed Price (per mmbtu)(1)	Fair Value Asset (in thousands)(2)
2012	5,520,000	$ 5.000	$ 9,704
2013	3,120,000	$ 5.288	4,155
2014	2,880,000	$ 5.590	3,526
2015	2,880,000	$ 5.861	3,523
			$ 20,908

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (mmbtu)(1)	Average Floor and Cap (per mmbtu)(1)	Fair Value Asset/(Liability) (in thousands)(2)
2012	Puts purchased	4,320,000	$ 4.074	$ 4,064
2012	Calls sold	4,320,000	$ 5.279	(133)
2013	Puts purchased	5,520,000	$ 4.395	4,469
2013	Calls sold	5,520,000	$ 5.443	(884)
2014	Puts purchased	3,840,000	$ 4.221	2,169
2014	Calls sold	3,840,000	$ 5.120	(1,480)
2015	Puts purchased	3,840,000	$ 4.296	2,395
2015	Calls sold	3,840,000	$ 5.233	(2,258)
				$ 8,342

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)[1]	Average Floor and Cap (per Bbl)[1]	Fair Value Asset/(Liability) (in thousands)[3]
2012	Puts purchased	60,000	$ 90.000	$ 379
2012	Calls sold	60,000	$ 117.912	(212)
2013	Puts purchased	60,000	$ 90.000	711
2013	Calls sold	60,000	$ 116.396	(396)
2014	Puts purchased	24,000	$ 80.000	248
2014	Calls sold	24,000	$ 121.250	(158)
2015	Puts purchased	24,000	$ 80.000	290
2015	Calls sold	24,000	$ 120.750	(183)
				$ 679
			Total net asset	$ 29,929

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(1) Mmbtu represents million British Thermal Units; Bbl represents barrels.
(2) Fair value based on forward NYMEX natural gas prices, as applicable.
(3) Fair value based on forward WTI crude oil prices, as applicable.

The Company s commodity price risk management activities include the estimated future natural gas and crude oil production of the Drilling Partnerships. Therefore, prior to Atlas Energy s acquisition of the Transferred Business, a portion of any unrealized derivative gain or loss was allocable to the limited partners of the Drilling Partnerships based on their share of estimated gas and oil production related to the derivatives not yet settled. Prior to the Company s acquisition of the Transferred Business, AEI monetized all of its derivative instruments, including those related to the future natural gas and oil production of the limited partners of the Drilling Partnerships. At December 31, 2011, hedge monetization cash proceeds of $36.2 million related to the amounts hedged on behalf of the Drilling Partnerships limited partners were included within cash and cash equivalents, and the Company will allocate the monetization net proceeds received to the Drilling Partnerships limited partners based on their natural gas and oil production generated over the period of the original derivative contracts. The derivative payable related to the hedge monetization proceeds at December 31, 2011 and net unrealized derivative assets at December 31, 2010 were payable to the limited partners in the Drilling Partnerships and are included in the combined balance sheets as follows (in thousands):

	December 31,	
	2011	2010
Current portion of derivative receivable from Drilling Partnerships	$	$ 138
Long-term derivative receivable from Drilling Partnerships		4,669
Current portion of derivative payable to Drilling Partnerships	(20,900)	(30,797)
Long-term portion of derivative payable to Drilling Partnerships	(15,272)	(34,796)
	$ (36,172)	$ (60,786)

NOTE 7 FAIR VALUE OF FINANCIAL INSTRUMENTS

Management has established a hierarchy to measure the Company s financial instruments at fair value which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Company uses a fair value methodology to value the assets and liabilities for their outstanding derivative contracts (see Note 6). The Company s commodity derivative contracts are valued based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 fair value measurements.

Information for assets and liabilities measured at fair value at December 31, 2011 and 2010 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
December 31, 2011				
Commodity-based derivatives	$	$ 29,929	$	$ 29,929
December 31, 2010				

Commodity-based derivatives	$	$ 66,100	$	$ 66,100

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

Management estimates the fair value of asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors at the date of establishment of an asset retirement obligation such as: amounts and timing of settlements, the credit-adjusted risk-free rate of the Company and estimated inflation rates. Information for assets that were measured at fair value on a nonrecurring basis for the years ended December 31, 2011 and 2010 were as follows (in thousands):

	Years Ended December 31,			
	2011		2010	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$ 713	$ 713	$ 472	$ 472
Total	$ 713	$ 713	$ 472	$ 472

Management estimates the fair value of the Company s long-lived assets by reviewing these assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, using estimates, assumptions and judgments regarding such events or circumstances. For December 31, 2011, 2010 and 2009, the Company recognized impairments of long-lived assets in the amounts of $7.0 million, $50.7 million and $156.4 million, respectively. Each of these impairments is defined as a Level 3 fair value measurement (See Note 2 *Impairment of Long-Lived Assets*).

NOTE 8 CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

In the ordinary course of its business operations, the Company has ongoing relationships with several related entities:

Relationship with the Company s Sponsored Investment Partnerships. The Company conducts certain activities through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Company serves as general partner and operator of the Drilling Partnerships and assumes customary rights and obligations for the Drilling Partnerships. As the general partner, the Company is liable for the Drilling Partnerships liabilities and can be liable to limited partners if it breaches its responsibilities with respect to the operations of the Drilling Partnerships. The Company is entitled to receive management fees, reimbursement for administrative costs incurred, and to share in the Company s revenue, and costs and expenses according to the respective partnership agreements.

NOTE 9 COMMITMENTS AND CONTINGENCIES

General Commitments

The Company leases equipment under leases with varying expiration dates through 2016. Rental expense was $1.9 million, $1.4 million and $1.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. Future minimum rental commitments for the next five years are as follows (in thousands):

Years Ended December 31,	
2012	$ 1,815
2013	1,429
2014	1,121
2015	1,053
2016	1,003
Thereafter	
	$ 10,041

The Company is the managing general partner of the Drilling Partnerships, and has agreed to indemnify each investor partner from any liability that exceeds such partner s share of Drilling Partnership assets. Subject to certain conditions, investor partners in certain Drilling Partnerships have the right to present their interests for purchase by the Company, as managing general partner. The Company is not obligated to purchase more than 5% to 10% of the units in any calendar year. Based on past experience, the management of the Company believes that any liability incurred would not be material. Also, the Company has agreed to subordinate a portion of its share of net partnership revenues from the Drilling Partnerships to the benefit of the investor partners until they have received specified returns, typically 10% per year determined on a cumulative basis, over a specific period, typically the first five to seven years, in accordance with the terms of the partnership agreements. For the years ended December 31, 2011, 2010 and 2009, $4.0 million, $10.9 million and $3.9 million, respectively, of the Company s revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the Drilling Partnerships.

Immediately following the acquisition of the Transferred Business, Atlas Energy received from Chevron $118.7 million related to a contractual cash transaction adjustment related to certain liabilities of the Transferred Business at February 17, 2011. Following the closing of the acquisition of the Transferred Business, Atlas Energy entered into a reconciliation process with Chevron to determine the final cash adjustment amount pursuant to the transaction agreement. The reconciliation period was ongoing at December 31, 2011, and certain amounts included within the contractual cash transaction adjustment are in dispute between the parties. The Company believes the amounts included within the contractual cash transaction adjustment are appropriate and is currently engaged in an on-going reconciliation process with Chevron. The resolution of the disputed amounts could result in the Company being required to repay a portion of the cash transaction adjustment (see Note 3). According to the transaction agreement, should the Company and Chevron not be able to come to an agreement during the reconciliation process, the two parties will enter into arbitration with a neutral public accounting firm. At December 31, 2011, the Company believes the range of loss associated with the disputed balances is between zero and $45.0 million.

In May 2011, the Company entered into a joint venture agreement with Mountain V Oil and Gas, Inc. (Mountain V), a privately-held oil and gas exploration and production company, under which the Company s Drilling Partnerships will invest approximately $35 million to drill 13 wells into the Marcellus Shale formation in Upshur County, West Virginia. As of December 31, 2011, the Company has drilled 11 wells, for which approximately $29.7 million has been invested. The Company expects to drill the remaining two wells during 2012.

The Company is party to employment agreements with certain executives that provide compensation and certain other benefits. The agreements also provide for severance payments under certain circumstances.

Legal Proceedings

The Company is a party to various routine legal proceedings arising out of the ordinary course of its business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on the Company s financial condition or results of operations.

NOTE 10 OPERATING SEGMENT INFORMATION

The Company s operations include three reportable operating segments. These operating segments reflect the way the Company manages its operations and makes business decisions. Operating segment data for the periods indicated are as follows (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Gas and oil production			
Revenues	$ 66,979	$ 93,050	$ 112,979
Operating costs and expenses	(17,100)	(23,323)	(25,557)
Depreciation, depletion and amortization expense	(27,430)	(36,668)	(40,067)
Asset impairment	(6,995)	(50,669)	(156,359)
Segment income (loss)	$ 15,454	$ (17,610)	$ (109,004)
Well construction and completion			
Revenues	$ 135,283	$ 206,802	$ 372,045
Operating costs and expenses	(115,630)	(175,247)	(315,546)
Segment income	$ 19,653	$ 31,555	$ 56,499
Other partnership management[(1)]			
Revenues	$ 45,260	$ 44,797	$ 52,252
Operating costs and expenses	(29,580)	(31,043)	(34,599)

Depreciation, depletion and amortization expense	(3,439)	(4,090)	(3,645)
Segment income	$ 12,241	$ 9,664	$ 14,008

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Reconciliation of segment income (loss) to net income (loss) from continuing operations						
Segment income (loss)						
Gas and oil production	$	15,454	$	(17,610)	$	(109,004)
Well construction and completion		19,653		31,555		56,499
Other partnership management		12,241		9,664		14,008
Total segment income (loss)		47,348		23,609		(38,497)
General and administrative expenses(2)		(27,536)		(11,381)		(15,832)
Gain (loss) on asset sales(2)		87		(2,947)		
Net income (loss) from continuing operations	$	19,899	$	9,281	$	(54,329)
Capital expenditures						
Gas and oil production	$	38,362	$	73,400	$	89,389
Well construction and completion						
Other partnership management		3,223		17,200		9,900
Corporate and other		5,739		3,008		13
Total capital expenditures	$	47,324	$	93,608	$	99,302

	December 31,			
		2011		**2010**
Balance sheet				
Goodwill:				
Gas and oil production	$	18,145	$	18,145
Well construction and completion		6,389		6,389
Other partnership management		7,250		7,250
	$	31,784	$	31,784
Total assets:				
Gas and oil production	$	593,320	$	593,368
Well construction and completion		6,987		9,627
Other partnership management		44,981		37,677
Corporate and other		55,825		8,560
	$	701,113	$	649,232

(1) Includes revenues and expenses from well services, transportation, administration and oversight and other, net that do not meet the quantitative threshold for reporting segment information.

(2) The Company notes that loss on asset sales and general and administrative expenses have not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

NOTE 11 SUBSEQUENT EVENTS

Acquisition of Assets from Carrizo Oil & Gas, Inc. On March 15, 2012, Atlas Resource Partners entered into a definitive agreement with Carrizo Oil & Gas, Inc. to purchase certain assets for $190 million in cash (the Acquisition). The purchase price is subject to certain post-closing adjustments based on, among other things, environmental and title defects, if any. The assets being acquired include interests in approximately 200 natural gas wells producing from the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas, and related proved undeveloped acres as well as gathering pipelines and associated gathering facilities that service certain of the acquired wells. The closing of the Acquisition is expected to occur on or before April 30, 2012, and is subject to customary closing conditions.

To partially fund the Acquisition, on March 15, 2012 Atlas Resource Partners executed a unit purchase agreement with several purchasers for the sale of 6.0 million of our common units at a negotiated purchase price per unit of $20.00, for anticipated gross proceeds of $120.0 million. The issuance of the common units is subject to customary closing conditions, including the closing of the Acquisition.

On March 15, 2012, Atlas Resource Partners executed a commitment letter with Wells Fargo Bank, N.A., as administrative agent for the lenders under the credit facility, for the purpose of amending the facility to increase the borrowing base to $250.0 million and the maximum lender commitment to $500.0 million. The closing of the amendment to the facility is expected to occur on or before April 30, 2012, and is subject to customary closing conditions, including the closing of the Acquisition.

Credit Facility. On March 5, 2012, Atlas Energy s credit facility was amended and restated so that it assigned, and Atlas Resource Partners assumed, Atlas Energy s rights, privileges and obligations under the credit facility. Subject to the March 15, 2012 commitment letter described above, the credit facility continues to have maximum lender commitments of $300 million, a borrowing base of $138 million and matures in March 2016. Up to $20.0 million of the credit facility may be in the form of standby letters of credit. Atlas Resource Partners obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by substantially all of Atlas Resource Partners subsidiaries. Borrowings under the credit facility bear interest, at Atlas Resource Partners election, at either LIBOR plus an applicable margin between 2.00% and 3.25% 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%. Atlas Resource Partners is also required to pay a fee of 0.5% per annum on the unused portion of the borrowing base, which is included within interest expense on its combined statements of operations.

The credit agreement contains customary covenants that limit Atlas Resource Partners ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The credit agreement also requires Atlas Resource Partners to maintain a ratio of Total Funded Debt (as defined in the credit agreement) to four quarters (actual or annualized, as applicable) of EBITDA (as defined in the credit agreement) not greater than 3.75 to 1.0 as of the last day of any fiscal quarter, a ratio of current assets (as defined in the credit agreement) to current liabilities (as defined in the credit agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter, and a ratio of four quarters (actual or annualized, as applicable) of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.5 to 1.0 as of the last day of any fiscal quarter.

Secured Hedge Facility. On March 5, 2012, Atlas Resource Partners entered into a secured hedge facility agreement with a syndicate of banks under which certain recently formed investment partnerships are eligible to participate in Atlas Resource Partners hedging arrangements. 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.

Formation and distribution of Atlas Resource Partners, L.P. In February 2012, the board of directors of the general partner of Atlas Energy approved the distribution of approximately 5.24 million Atlas Resource Partners common units, which were distributed on March 13, 2012 to Atlas Energy s unitholders using a ratio of 0.1021 Atlas Resource Partners limited partner units for each Atlas Energy common unit owned on the record date of February 28, 2012. In connection with the distribution, the board of directors of the general partner of Atlas Energy also approved the transfer to Atlas Resource Partners of Atlas Energy s E&P Operations. The distribution of Atlas Resource Partners limited partner units represented approximately 19.6% of its outstanding limited partner interests. Subsequent to the distribution, Atlas Energy owns a 2% general partner interest, all of the incentive distribution rights and common units representing an approximate 78.4% limited partner interest in Atlas Resource Partners. Atlas Resource Partners common units began trading regular-way under the ticker symbol ARP on the New York Stock Exchange on March 14, 2012.

NOTE 12 SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserve Information. The preparation of the Company s natural gas and oil reserve estimates was completed in accordance with its prescribed internal control procedures by its reserve engineers. The accompanying reserve information included below is attributable to the reserves of the Company and was derived from the reserve reports prepared for Atlas Energy s and/or AEI s annual Form 10-K for the years ended December 31, 2011, 2010 and 2009. For the periods presented, Wright and Company, Inc., an independent third-party reserve engineer, was retained to prepare a report of proved reserves related to the Company. The reserve information for the Company includes natural gas and oil reserves which are all located in the United States, primarily in Colorado, Indiana, New York, Ohio, Pennsylvania, Tennessee and West Virginia. The independent reserves engineer s evaluation was based on more than 35 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. The Company s internal control procedures include verification of input data delivered to its third-party reserve specialist, as well as a multi-functional management review. The preparation of reserve estimates was overseen by our Senior Reserve Engineer, who is a member of the Society of Petroleum Engineers and has more than 13 years of natural gas and oil industry experience. The reserve estimates were reviewed and approved by the Company s senior engineering staff and management, with final approval by the Company s Executive Vice President.

The reserve disclosures that follow reflect estimates of proved reserves, proved developed reserves and proved undeveloped reserves, net of royalty interests, of natural gas, crude oil and natural gas liquids owned at year end and changes in proved reserves during the last three years. 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 developed reserves are those 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 undeveloped reserves are 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. In accordance with the prevailing accounting literature, the proved reserves quantities and future net cash flows as of December 31, 2011, 2010 and 2009 were estimated using an unweighted 12-month average pricing based on the prices on the first day of each month during the years ended December 31, 2011, 2010 and 2009, including adjustments related to regional price differentials and energy content.

There are numerous uncertainties inherent in estimating quantities of proven reserves and in projecting future net revenues and the timing of development expenditures. The reserve data presented represents estimates only and should not be construed as being exact. In addition, the standardized measures of discounted future net cash flows may not represent the fair market value of oil and gas reserves included within the Company or the present value of future cash flows of equivalent reserves, due to anticipated future changes in oil and gas prices and in production and development costs and other factors, for their effects have not been proved.

Reserve quantity information and a reconciliation of changes in proved reserve quantities included within the Company are as follows (unaudited):

	Gas (Mcf)	Oil (Bbls) (1)
Balance, January 1, 2009	203,636,945	1,725,834
Extensions, discoveries and other additions(2)	58,349,703	25,737
Sales of reserves in-place	(101,295)	(1,944)
Purchase of reserves in-place	110,953	302
Transfers to limited partnerships	(22,125,866)	
Revisions(3)	(42,110,044)	265,371
Production	(14,105,432)	(192,578)
Balance, December 31, 2009	183,654,964	1,822,722
Extensions, discoveries and other additions(2)	64,776,600	
Sales of reserves in-place	(9,241,358)	
Purchase of reserves in-place	366,276	1,203
Transfers to limited partnerships	(8,824,000)	
Revisions(4)	(41,580,400)	326,913
Production	(13,087,079)	(318,303)
Balance, December 31, 2010	176,065,003	1,832,535
Extensions, discoveries and other additions(2)	9,966,952	8,217
Sales of reserves in-place	(990)	
Purchase of reserves in-place	586,662	2,216
Transfers to limited partnerships	(6,042,432)	

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	Gas (Mcf)	Oil (Bbls) (1)
Revisions(5)	(11,436,615)	77,661
Production	(11,462,149)	(274,330)
Balance, December 31, 2011	157,676,431	1,646,299
Proved developed reserves at:		
January 1, 2009	66,622,045	48,170
December 31, 2009	140,392,057	1,785,712
December 31, 2010	137,393,017	1,832,535
December 31, 2011	138,403,225	1,638,083
Proved undeveloped reserves at:		
January 1, 2009	137,014,900	1,677,664
December 31, 2009	43,262,907	37,010
December 31, 2010	38,671,986	
December 31, 2011	19,273,206	8,216

(1) Includes NGL information as reserve amounts are immaterial.
(2) Principally includes increases of proved reserves due to the addition of Marcellus wells.
(3) Represents a decrease in the price of natural gas and oil compared from the year ended December 31, 2008 to the year ended December 31, 2009, based on the change in pricing methodology to a twelve-month unweighted average based on the first-day-of-the-month prices for the year ended December 31, 2009.
(4) Represents a downward revision, and related impairment charge, related to the Company s shallow natural gas wells in Pennsylvania and Ohio, principally due to the reduction of drilling plans in the Clinton/Medina and Upper Devonian formations over the next five years.
(5) Represents a downward revision of proved undeveloped reserves in the New Albany Shale due to the reduction of certain drilling plans related to the Company s shallow natural gas wells.

Capitalized Costs Related to Oil and Gas Producing Activities. The components of capitalized costs related to oil and gas producing activities of the Company during the periods indicated were as follows (in thousands):

	Year Ended December 31,	
	2011	2010
Natural gas and oil properties:		
Proved properties	$ 892,907	$ 847,101
Unproved properties	43,253	42,520
Support equipment	9,413	8,138
	945,573	897,759
Accumulated depreciation, depletion and amortization(1)	(451,924)	(419,375)
Net capitalized costs	$ 493,649	$ 478,384

(1) During the year ended December 31, 2011, the Company recognized $7.0 million of impairment related to its shallow natural gas wells in the Niobrara Shale. During the year ended December 31, 2010, the Company recognized $50.7 million of impairment related to its shallow natural gas wells in the Chattanooga and Upper Devonian shales.

Results of Operations from Oil and Gas Producing Activities. The results of operations related to the Company s oil and gas producing activities during the periods indicated were as follows (in thousands):

	Years Ended December 31,		
	2011	**2010**	**2009**
Revenues	$ 66,979	$ 93,050	$ 112,979
Production costs	(17,100)	(23,323)	(25,557)
Depreciation, depletion and amortization	(27,430)	(36,668)	(40,067)
Long-lived asset impairment[1]	(6,995)	(50,669)	(156,359)
	$ 15,454	$ (17,610)	$ (109,004)

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(1) During the year ended December 31, 2011, the Company recognized $7.0 million of impairment related to its shallow natural gas wells in the Niobrara Shale. During the year ended December 31, 2010, the Company recognized $50.7 million of impairment related to its shallow natural gas wells in the Chattanooga and Upper Devonian shales. During the year ended December 31, 2009, the Company recognized $156.4 million of impairment related to its shallow natural gas wells in the Upper Devonian Shale.

Costs incurred in Oil and Gas Producing Activities. The costs incurred by the Company in its oil and gas activities during the periods indicated are as follows (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Property acquisition costs:			
Proved properties	$ 9,199	$ 3,007	$ 20
Unproved properties	323	2,259	12,123
Exploration costs	1,156		
Development costs	29,809	74,821	68,101
Total costs incurred in oil & gas producing activities	$ 40,487	$ 80,087	$ 80,244

The following schedule presents the standardized measure of estimated discounted future net cash flows relating to the Company s proved oil and gas reserves. The estimated future production was priced at a twelve-month average for the years ended December 31, 2011, 2010 and 2009, adjusted only for regional price differentials and energy content. The resulting estimated future cash inflows were reduced by estimated future costs to develop and produce the proved reserves based on year-end cost levels and includes the effect on cash flows of settlement of asset retirement obligations on gas and oil properties. The future net cash flows were reduced to present value amounts by applying a 10% discount factor. The standardized measure of future cash flows was prepared using the prevailing economic conditions existing at the dates presented and such conditions continually change. Accordingly, such information should not serve as a basis in making any judgment on the potential value of recoverable reserves or in estimating future results of operations (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Future cash inflows	$ 949,286	$ 1,045,725	$ 993,206
Future production costs	(425,493)	(464,392)	(429,630)
Future development costs	(27,266)	(35,357)	(75,011)
Future net cash flows	496,527	545,976	488,565
Less 10% annual discount for estimated timing of cash flows	(276,668)	(309,346)	(309,747)
Standardized measure of discounted future net cash flows	$ 219,859	$ 236,630	$ 178,818

The following table summarizes the changes in the standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves (in thousands), including amounts related to asset retirement obligations. Since the Company allocates taxable income to its owner, no recognition has been given to income taxes:

	Years Ended December 31,		
	2011	2010	2009
Balance, beginning of year	$ 236,630	$ 178,818	$ 271,616

Increase (decrease) in discounted future net cash flows:			
Sales and transfers of oil and gas, net of related costs	(46,304)	(51,522)	(38,316)
Net changes in prices and production costs	(34)	41,978	(95,712)
Revisions of previous quantity estimates	757	21,598	22,126
Development costs incurred	1,842	7,565	9,936
Changes in future development costs	(3,591)	(803)	(43,615)
Transfers to limited partnerships	(8,022)	(4,148)	(9,834)
Extensions, discoveries, and improved recovery less related costs	14,923	54,887	24,882
Purchases of reserves in-place	736	492	141
Sales of reserves in-place	(1)	(12,254)	(303)
Accretion of discount	23,663	17,882	25,298
Estimated settlement of asset retirement obligations	(3,105)	(6,074)	(2,252)
Estimated proceeds on disposals of well equipment	3,363	2,227	2,285
Changes in production rates (timing) and other	(998)	(14,016)	12,566
Outstanding, end of year	$ 219,859	$ 236,630	$ 178,818

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our general partner s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our general partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our general partner s Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2011, our disclosure controls and procedures were not effective at the reasonable assurance level due to the material weakness noted below.

Management s Report on Internal Control over Financial Reporting

The management of our general partner is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including our general partner s Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based upon criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control Integrated Framework (COSO framework).

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods cannot be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.

Based on our evaluation under the COSO framework, management concluded that our internal control over financial reporting was not effective at the reasonable assurance level as of December 31, 2011. During the year ended December 31, 2011, management concluded that our internal control over financial reporting was not effective, because our predecessor s financial statements that were initially filed in our registration statement on Form 10 did not include general and administrative expenses prior to February 17, 2011. We had filed such financial statements without such expenses because our predecessor s assets were not managed as a separate business segment. We revised the financial statements included in the Form 10 and this report to include general and administrative expenses for periods prior to February 17, 2011 based on allocations that we believe reflect the approximate general and administrative costs of our underlying business segments. The failure to include these general and administrative expenses in our earlier filing was determined to be a material weakness in internal control over financial reporting around the review and interpretation of complex regulatory accounting standards. Subsequent to our discovery of the material weakness, we have taken steps to remediate the material weakness,

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including the review of accounting requirements related to the recognition of general and administrative expenses. We believe these actions have strengthened our internal control over financial reporting and will address the material weakness identified as of December 31, 2011.

Grant Thornton LLP, an independent registered public accounting firm, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2011, which is included herein.

Other than the previously mentioned items, there have been no changes in our internal control over financial reporting during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Resource Partners, L.P.

We have audited Atlas Resource Partners, L.P. s (a Delaware limited partnership) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Atlas Resource Partners, L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Atlas Resource Partners L.P. s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company s annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management s assessment. Management has identified a material weakness in controls around the review and interpretation of complex regulatory accounting standards related to the allocation of general and administrative expenses within the financial statements of its predecessor for periods prior to February 17, 2011.

In our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Atlas Resource Partners, L.P. has not maintained effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheet of Atlas Resource Partners, L.P. as of December 31, 2011. The material weakness identified above was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2011 financial statement, and this report does not affect our report dated March 29, 2012, which expressed an unqualified opinion on that financial statement.

We do not express an opinion or any other form of assurance on management s statement referring to the steps taken to remediate the identified material weakness.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

March 29, 2012

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our general partner manages our activities. Unitholders do not directly or indirectly participate in our management or operation or have actual or apparent authority to enter into contracts on our behalf or to otherwise bind us. Our general partner will be liable, as general partner, for all of our debts to the extent not paid, except to the extent that indebtedness or other obligations incurred by us are specifically with recourse only to our assets. Whenever possible, our general partner intends to make any of our indebtedness or other obligations with recourse only to our assets.

As set forth in our partnership governance guidelines and in accordance with NYSE listing standards, the non-management members of our general partner s board of directors will meet in executive session regularly without management. The managing board member who presides at these meetings will rotate each meeting. The purpose of these executive sessions will be to promote open and candid discussion among the non-management board members. Interested parties wishing to communicate directly with the non-management members may contact the chair of our audit committee by writing to them at Atlas Resource Partners GP, LLC, 1845 Walnut Street, 10th Floor, Philadelphia, Pennsylvania 19103, c/o Chair, Audit Committee.

The independent board members comprise all of the members of the managing board s committees: the conflicts committee and the audit committee. The conflicts committee has the authority to review specific matters as to which the managing board believes there may be a conflict of interest to determine if the resolution of the conflict proposed by our general partner is fair and reasonable to us. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls.

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management or operation. Rather, personnel employed by Atlas Energy will manage and operate our business. Some of the officers of our general partner may spend a substantial amount of time managing the business and affairs of Atlas Energy and its affiliates other than us and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

Reimbursement of Expenses of Our General Partner and Its Affiliates

Our general partner does not receive any management fee or other compensation for its services apart from its general partner and incentive distributions. We reimburse our general partner and its affiliates, including Atlas Energy, for all expenses incurred on our behalf. These expenses include the costs of employee, officer and managing board member compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner as determined by our general partner in its sole discretion, and does not set any aggregate limit on such reimbursements. Our general partner allocates the costs of employee and officer compensation and benefits based upon the amount of business time spent by those employees and officers on our business.

Board of Directors and Officers of Our General Partner Following the Separation

The following table sets forth information as of March 15, 2012 with respect to those persons who serve as the officers of and on the board of directors of, our general partner:

Name	Age	Position(s)
Edward E. Cohen	73	Chairman of the Board and Chief Executive Officer
Jonathan Z. Cohen	41	Vice Chairman of the Board
Matthew A. Jones	50	President, Chief Operating Officer and Director
Anthony Coniglio	43	Director
DeAnn Craig	60	Director
Jeffrey C. Key	46	Director

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Name	Age	Position(s)
Bruce Wolf	63	Director
Sean P. McGrath	40	Chief Financial Officer
Daniel C. Herz	35	Senior Vice President of Corporate Development & Strategy
Freddie M. Kotek	56	Senior Vice President of Investment Partnership Division
Lisa Washington	44	Chief Legal Officer and Secretary
Jeffrey C. Simmons	53	Senior Vice President of Operations
Jerry Dominey	58	Vice President of Exploration and Chief Geologist
Brad O. Eubanks	54	Vice President of Land
Roger R. Myers	54	Vice President of Completion Services
Jack Crook	53	Vice President of Environment, Health and Safety
Dana Greathouse	56	Vice President of Drilling
Daniel Kortum	62	Vice President of Energy Marketing
Joel S. Heiser	45	General Counsel and Assistant Secretary
Jeffrey M. Slotterback	29	Chief Accounting Officer

Edward E. Cohen has been the Chairman of the Board and Chief Executive Officer of our general partner since February 2012. Mr. Cohen has served as Chief Executive Officer and President of Atlas Energy s general partner since February 2011. Edward Cohen served as Chairman of the Board of Atlas Energy s general partner from January 2006 until February 2011 and as Chief Executive Officer of Atlas Energy s general partner from January 2006 until February 2009 and has served on the Executive Committee of the Board of Directors of Atlas Energy s general partner since 2006. Edward Cohen was Chairman of the Board of Directors and Chief Executive Officer of Atlas Energy, Inc. from September 2000 until February 2011. Edward Cohen served as President of Atlas Energy, Inc. from September 2000 until October 2009. Edward Cohen served as Chairman of the Board of Directors and Chief Executive Officer of Atlas Energy Resources, LLC from June 2006 until February 2011. Edward Cohen has been Chairman of the Managing Board of Atlas Pipeline Partners GP, LLC since 1999 and was Chief Executive Officer of Atlas Pipeline Partners GP, LLC from 1999 until January 2009. In addition, Edward Cohen has been Chairman of the Board of Directors of Resource America, Inc. since 1990 and was its Chief Executive Officer from 1988 until 2004 and President from 2000 until 2003; was Chairman of the Board of Directors of Resource Capital Corp. from September 2005 until November 2009, and currently is a member of its Board of Directors; and is Chairman of the Board of Directors of Brandywine Construction & Management, Inc. (a property management company) since 1994. Edward Cohen is the father of Jonathan Cohen. Edward Cohen brings to the board of directors of our general partner the vast experience that he has accumulated through his activities as a financier, investor and operator in various parts of the country.

Jonathan Z. Cohen has served as the Vice Chairman of the Board of our general partner since February 2012. Mr. Cohen has served as Chairman of the Board of Atlas Energy s general partner from February 2011 to January 2012 and as Executive Chairman since January 2012. Jonathan Cohen served as Vice Chairman of the Board of Directors of Atlas Energy s general partner from January 2006 until February 2011 and has served as Chair of the Executive Committee of the Board of Atlas Energy s general partner since 2006. Jonathan Cohen was Vice Chairman of the Board of Directors of Atlas Energy, Inc. from September 2000 until February 2011 and Chairman of Atlas Energy, Inc. s Executive Committee from October 2009 until February 2011. Jonathan Cohen served as Vice Chairman of Atlas Energy Resources, LLC from June 2006 until February 2011. Jonathan Cohen has been Vice Chairman of the Managing Board of Atlas Pipeline Partners GP, LLC since 1999. Jonathan Cohen has been a senior officer of Resource America, Inc. (a publicly-traded specialized asset management company) since 1998, serving as Chief Executive Officer since 2004, President since 2003 and a director since 2002. Jonathan Cohen has been Chief Executive Officer, President and a director of Resource Capital Corp. (a publicly-traded real estate investment trust) since 2005. Jonathan Cohen is a son of Edward Cohen. Jonathan Cohen s financial, business, operational and energy experience as well the experience that he has accumulated through his activities as a financier and investor add strategic vision to the board of directors of our general partner to assist with our growth and development.

Matthew A. Jones has served as President, Chief Operating Officer and Director of our general partner since March 2012. Mr. Jones has served as a Senior Vice President of Atlas Energy s general partner and President and Chief Operating Officer of the exploration and production division of Atlas Energy s general partner since February 2011. Mr. Jones was Chief Financial Officer of Atlas Energy, Inc. from March 2005 until February 2011 and Executive Vice President of Atlas Energy, Inc. from October 2009 until February 2011. Mr. Jones was Chief Financial Officer of Atlas Energy Resources, LLC and Atlas Energy Management, Inc., a wholly owned subsidiary of Atlas Energy, Inc., from June 2006 until February 2011. Mr. Jones served as Chief Financial Officer of Atlas Energy GP, LLC (which is Atlas Energy s general partner) from January 2006 until September 2009 and served as a member of the Board of Directors of Atlas Energy GP, LLC from February 2006

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to February 2011. Mr. Jones served as Chief Financial Officer of Atlas Pipeline Partners GP, LLC from March 2005 to September 2009. Mr. Jones is a Chartered Financial Analyst. Mr. Jones brings extensive financial and operational knowledge of our company, derived from his long background of service to our predecessors, to the board of directors of our general partner.

Anthony Coniglio has served as a Director of our general partner since March 2012. Mr. Coniglio, since June 2011, focused his efforts on founding a residential mortgage company for which he will also serve as Chief Executive Officer. From August 1997 until June 2011, Mr. Coniglio held various positions with J.P. Morgan Securities LLC and Chase Securities, Inc. (J.P. Morgan s predecessor firm). From April 2004 through June 2011, Mr. Coniglio was a Managing Director at J.P. Morgan Securities LLC and served as Co-head of the Specialty Finance and Asset Management Investment Banking Group. Prior to his tenure at J.P. Morgan, Mr. Coniglio was a Vice President in the Structured Finance Group at CIBC for approximately five years. From 1991 until 1993, Mr. Coniglio was employed as a Certified Public Accountant with PricewaterhouseCoopers LLP. His professional licenses include Series 7, 24, 63 and 79. He has extensive financial services experience, including a deep understanding of the banking, consumer finance and commercial finance industries. Mr. Coniglio brings a comprehensive knowledge of corporate finance, structured finance, capital markets, accounting, credit and treasury matters to the board of directors of our general partner.

Dolly Ann (DeAnn) Craig has served as a Director of our general partner since March 2012. Dr. DeAnn Craig has been a consultant to Atlas Energy since 2011. Dr. Craig has been an Adjunct Professor in the Petroleum Engineering Department of the Colorado School of Mines since 2009, and also serves as a member of the Colorado Oil and Gas Conservation Commission from 2009 until 2012. Dr. Craig was the Senior Vice President Asset Assessment with CNX Gas Corporation from 2007 until 2009. Previously, she served as President of Phillips Petroleum Resources, a Canadian subsidiary of Phillips Petroleum, and Manager of Worldwide Drilling and Production of Phillips Petroleum. Dr. Craig has been a director for Samson Oil & Gas Limited since July 2011 and chairs Samson s audit committee. Dr. Craig is a Registered Professional Engineer in the State of Colorado. Dr. Craig brings a strong technical and operational background and practical expertise in issues relating to exploration and production activities to the board of directors of our general partner.

Jeffrey C. Key has served as a Director of our general partner since February 2012. Mr. Key is Vice President, Corporate Development for Tekelec, a supplier of telecommunications equipment, and has been with Tekelec since 2004. From 2002 to 2004, Mr. Key was the Managing Partner of his own consulting firm, Key Technology Partners, LLC, which provided strategy development and planning services to communications and networking technology companies. From 2000 to 2002, Mr. Key was a Managing Director of Investment Banking at Bear, Stearns & Co. Inc. Mr. Key served as an independent member of the Managing Board and a member of the Audit Committee of Atlas Energy from 2006 until February 2011. Mr. Key has extensive experience in finance, financial statement analysis, strategic planning and growth projects, complemented by investment experience. Mr. Key brings a strong finance and accounting background to the board of directors of our general partner, and, as a financial expert, will serve as the Chair of the Audit Committee. In addition, Mr. Key s finance and planning experience are valuable in analyzing capital needs and evaluating capital alternatives.

Bruce Wolf has served as a Director of our general partner since March 2012. Mr. Wolf has been President of Homard Holdings, LLC, a wine manufacturer and distributor, since September 2003. Mr. Wolf has been of counsel with Picadio, Sneath, Miller & Norton, P.C., Pittsburgh, PA, since May 2003. Additionally, since June 1999, Mr. Wolf has been a consultant in connection with energy and securities matters, conducting research and providing expert testimony and litigation support. Mr. Wolf was a Senior Vice President of Atlas America, Inc. from October 1998 to May 1999 and, before that, Secretary and General Counsel of Atlas Energy Group from 1980. Mr. Wolf is a seasoned director, having served as an independent member of the Board of Directors of Atlas Energy Resources, LLC from December 2006 until September 2009. Mr. Wolf also served on the board Atlas Energy from 2009 until February 2011. Mr. Wolf combines his extensive knowledge of energy with strong legal and financial knowledge.

Sean P. McGrath has served as Chief Financial Officer of our general partner since February 2012. .Sean McGrath has served as Chief Financial Officer of Atlas Energy s general partner since February 2011. Mr. McGrath was Chief Accounting Officer of Atlas Energy, Inc. and Chief Accounting Officer of Atlas Energy Resources, LLC from December 2008 until February 2011. Mr. McGrath served as Chief Accounting Officer of Atlas Energy GP, LLC (which is Atlas Energy s general partner) from January 2006 until November 2009 and as Chief Accounting Officer of Atlas Pipeline Partners GP, LLC from May 2005 until November 2009. Mr. McGrath was Controller of Sunoco Logistics Partners L.P., a publicly-traded partnership that transports, terminals and stores refined products and crude oil, from 2002 until 2005. From 1998 until 2002, Mr. McGrath was Assistant Controller of Asplundh Tree Expert Co., a utility services and vegetation management company. Mr. McGrath is a Certified Public Accountant.

Daniel C. Herz has served as Senior Vice President of Corporate Development and Strategy of our general partner since March 2012. Mr. Herz has served as Senior Vice President of Corporate Development and Strategy of Atlas Energy s general partner since February 2011. Mr. Herz has been Senior Vice President of Corporate Development of Atlas Energy s general partner and Atlas Pipeline Partners GP, LLC since August 2007. He also was Senior Vice President of Corporate Development of Atlas Energy, Inc. and Atlas Energy Resources, LLC from August 2007 until February 2011. Before that, Mr. Herz was Vice President of Corporate Development of Atlas Energy, Inc. and Atlas Pipeline Partners GP, LLC from December 2004 and of Atlas Energy s general partner from January 2006. Prior to joining Atlas Energy, Inc. and Atlas Pipeline Partners GP, LLC, Mr. Herz was an Investment Banker with Banc of America Securities from 1999 to 2003.

Freddie M. Kotek has served as Senior Vice President of our general partner since March 2012. Mr. Kotek has served as Senior Vice President of Atlas Energy s general partner since February 2011. Mr. Kotek was an Executive Vice President of Atlas Energy, Inc. from February 2004 until February 2011 and served as a director of Atlas Energy, Inc. from September 2001 until February 2004. Mr. Kotek also was Chief Financial Officer of Atlas Energy, Inc. from February 2004 until March 2005. Mr. Kotek has been Chairman of Atlas Resources, LLC since September 2001 and Chief Executive Officer and President since January 2002. Mr. Kotek was a Senior Vice President of Resource America, Inc. from 1995 until May 2004 and President of Resource Leasing, Inc., a wholly owned subsidiary of Resource America, Inc., from 1995 until May 2004.

Lisa Washington has served as Chief Legal Officer and Secretary of our general partner since February 2012. Ms. Washington has served as Vice President, Chief Legal Officer and Secretary of Atlas Energy s general partner since February 2011. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy GP, LLC from January 2006 to October 2009 and as a Senior Vice President from October 2008 to October 2009. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Pipeline Partners GP, LLC from November 2005 to October 2009 and as a Senior Vice President from October 2008 to October 2009. Ms. Washington was a Vice President of Atlas Pipeline Partners GP, LLC from November 2005 until October 2008. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy, Inc. from November 2005 until February 2011 and as a Senior Vice President from October 2008 until February 2011. Ms. Washington was a Vice President of Atlas Energy, Inc. from November 2005 until October 2008. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy Resources, LLC from 2006 until February 2011 and as a Senior President from July 2008 until February 2011. Ms. Washington was a Vice President of Atlas Energy Resources, LLC from 2006 until July 2008. From 1999 to 2005, Ms. Washington was an attorney in the business department of the law firm of Blank Rome LLP.

Jeffrey C. Simmons has served as Senior Vice President of Operations of our general partner since March 2012. Mr. Simmons has been a Senior Vice President of Atlas Energy Management, Inc. since 2006. Mr. Simmons was a director of Atlas America, LLC from January 2002 until February 2004. Mr. Simmons was a Vice President of Resource America from April 2001 until May 2004. Mr. Simmons served as Vice President of Operations for Atlas Resources, LLC from July 1999 until December 2000 and for Atlas America, LLC from 1998 until December 2000. Mr. Simmons joined Resource America in 1986 as a senior petroleum engineer and has served in various executive positions with its energy subsidiaries since then.

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

Brad O. Eubanks has served as Vice President, Land of our general partner since March 2012. Mr. Eubanks has served as Vice President, Land of Atlas Energy s general partner since August 2011. Mr. Eubanks began his career with Shell Oil Company in 1970 as a Landman. From 1986 until 1998 he served as a District Land Manager for various regions of the country for Shell Oil. In 1998, be became Manager of Land and Acquisitions for Shell Louisiana Company. In 2001, he became Team Lead Rockies for Shell Exploration & Production, Inc., and in December 2009 became Team Leader-Gulf of Mexico for Shell Offshore, Inc. Mr. Eubanks is a Certified Professional Landman in the State of Oklahoma.

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

Jack Crook has served as Vice President of Environment, Health and Safety of our general partner since March 2012. Mr. Crook has served as Operations & Compliance Chief of the Pennsylvania Department of Environmental Protection from March 2008 to March 2012 and Water Supply Supervisor from September 2001 to March 2008.

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

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

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

Jeffrey M. Slotterback has served as Chief Accounting Officer of our general partner since March 2012. Mr. Slotterback has served as Chief Accounting Officer of Atlas Energy GP, LLC (which is Atlas Energy s general partner) since March 2011. Mr. Slotterback was the Manager of Financial Reporting for Atlas Energy, Inc. from July 2009 until February 2011 and then served as the Manager of Financial Reporting for Atlas Energy GP, LLC from February 2011 until March 2011. Mr. Slotterback served as Manager of Financial Reporting for both Atlas Energy GP, LLC and Atlas Pipeline Partners GP, LLC from May 2007 until July 2009. Mr. Slotterback was a Senior Auditor at Deloitte and Touche, LLP from 2004 until 2007, where he focused on energy and health care clients. Mr. Slotterback is a Certified Public Accountant.

We have assembled a board of directors of our general partner comprised of individuals who bring diverse but complementary skills and experience to oversee our business. Our directors collectively have a strong background in energy, finance, law, accounting and management. Based upon the experience and attributes of the directors discussed herein, our board of our general partner determined that each of the directors should, as of the date hereof, serve on the board of our general partner.

Section 16(a) Beneficial Ownership Reporting Compliance

Under Section 16(a) of the Securities Exchange Act of 1934 and rules and regulations promulgated by the SEC, our directors, executive officers and beneficial owners of more than 10% of any class of equity security are required to file periodic reports of their ownership, and changes in that ownership, with the SEC. During the fiscal year ended December 31, 2011, we were not a reporting company under the Exchange Act and accordingly, our directors and officers were not subject to the reporting requirements under Section 16(a) of the Exchange Act during fiscal 2011.

Committees of the Board of Directors of our General Partner

The standing committees of the board of directors of our general partner are the audit committee and the conflicts committee.

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Audit Committee. The audit committee s duties include recommending to the board of directors of our general partner the independent public accountants to audit our financial statements and establishing the scope of, and overseeing, the annual audit. The committee also approves any other services provided by public accounting firms. The audit committee provides assistance to the board of directors of our general partner in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor s qualifications and independence and the performance of internal audit function. The audit committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that our management and the board of directors of our general partner have established. In doing so, it is the responsibility of the audit committee to maintain free and open communication between the committee and the independent auditors, internal accounting function and our management. Members of the audit committee must meet the independence standards established by the NYSE and the Securities Exchange Act of 1934 to serve on an audit committee of a board of directors. The board of directors of our general partner has adopted a written charter for the audit committee, a current copy of which is available on our web site at www.atlasresourcepartners.com, and we will make a printed copy available to any unitholder who so requests. The members of the audit committee are Mr. Coniglio, Mr. Key and Mr. Wolf. Mr. Key is the chairman of the audit committee and the board of directors of our general partner has determined that Mr. Key is an audit committee financial expert, as defined by SEC rules.

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

Code of Business Conduct and Ethics

We have adopted a code of business conduct and ethics that applies to the principal executive officer, principal financial officer and principal accounting officer of our general partner, as well as to persons performing services for us generally. We will make a printed copy of our code of ethics available to any unitholder who so requests. Requests for print copies may be directed to us as follows: Atlas Resource Partners, L.P., Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275-1011, Attention: Secretary. The code of business conduct is also posted, and any waivers we grant thereunder will be posted, on our website at www.atlasresourcepartners.com.

Risk Oversight

We administer our risk oversight function through our audit committee which monitors material enterprise risks. The audit committee also reviews any major transactions or decisions affecting our risk profile or exposure, and reviews with counsel legal compliance and legal matters that could have a significant impact on our financial statements. Our audit committee also oversees our internal audit function. Our audit committee is also responsible for monitoring the integrity and ensuring the transparency of our financial reporting processes and systems of internal controls regarding finance, accounting and regulatory compliance. Our audit committee incorporates its risk oversight function into its regular reports to the board of directors of our general partner.

In addition to our audit committee s role in overseeing risk management, the full board of directors of our general partner regularly engages in discussions of the most significant risks that we face and how these risks are being managed. Our senior executives will provide regular updates about our strategies and objectives and the risks inherent within them at board and committee meetings and in regular reports. Board and committee meetings will also provide a venue for directors to discuss issues of concern with management. The Board and committees may call special meetings when necessary to address specific issues or matters that should be addressed before the next regularly scheduled meeting. In addition, our directors have access to our management at all levels to discuss any matters of interest, including those related to risk. Those members of management most knowledgeable of the issues will attend board meetings to provide additional insight into items being discussed, including risk exposures. In addition, senior executives of our key divisions as well as our Chief Financial Officer and Chief Legal Officer report directly to our President as well as our Chairman and Chief Executive Officer, which will provide them with visibility to our risk profile.

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ITEM 11. EXECUTIVE COMPENSATION
Compensation Committee Interlocks and Insider Participation

Neither we nor the board of directors of our general partner had a compensation committee for the year ended December 31, 2011. Compensation of the personnel of Atlas Energy and its affiliates who provide us with services is set by Atlas Energy and such affiliates. See Item 10, Reimbursement of Expenses of our General Partner and Its Affiliates, above and in Compensation Discussion and Analysis below.

None of the independent members of the board of directors of our general partner is an employee or former employee of ours, our general partner or Atlas Energy. No executive officer of our general partner is a director or executive officer of any entity in which an independent member of the board of directors of our general partner is a director or executive officer.

Compensation Discussion and Analysis

Introduction

We do not directly employ any persons to manage or operate our businesses. Instead, all of the persons (including executive officers of our general partner and other personnel) necessary for the management of our business are employed and compensated by Atlas Energy. Pursuant to our partnership agreement, our general partner manages our operations and activities through its and its affiliates employees (including employees of Atlas Energy and its general partner), and we reimburse our general partner for direct and indirect general and administrative expenses, including compensation expenses, incurred on our behalf (see discussion above in Item 10, Reimbursement of Expenses of our General Partner and Its Affiliates.

Historical Compensation

We and Atlas Resource Partners GP, LLC, our general partner, were recently formed. In addition, Atlas Energy has not historically allocated the compensation of its executive officers to our business. Therefore, we have incurred no cost or liability with respect to compensation of the executive officers of our general partner for the 2009, 2010 or 2011 fiscal years (or for any prior period).

Messrs. Edward E. Cohen, Jonathan Z. Cohen, Matthew A. Jones, Sean P. McGrath and Freddie M. Kotek are the named executive officers of Atlas Energy s general partner that are also executive officers of our general partner. Information relating to their compensation from Atlas Energy for the fiscal year ended December 31, 2011 (and the fiscal years ended December 31, 2009 and/or 2010 to the extent such an officer was a named executive officer for such fiscal year) is provided under Executive Compensation Atlas Energy Compensation Discussion and Analysis below. The named executive officers of Atlas Energy have received no additional compensation from us for the 2009, 2010 or 2011 fiscal years (or for any prior period), and it is not currently anticipated that we will pay additional annual cash or other compensation to such officers for service to us for such periods.

For fiscal year 2011, Atlas Energy allocated a portion of the compensation of its named executive officers to Atlas Pipeline Partners, L.P. The remainder of such compensation was borne directly by Atlas Energy. Because we were recently formed and were not operated as a separate entity, Atlas Energy did not allocate the compensation of its named executive officers to our business for such period.

We expect that, for fiscal 2012 and beyond, certain of the executive officers of our general partner will devote the majority of their time to our business (and, therefore, a majority of their compensation will be reimbursable by us), while other officers will have responsibilities for both us and Atlas Energy and Atlas Pipeline Partners and will devote less than a majority of their time to our business (and, therefore, less than a majority of their compensation will be reimbursable by us). Each of Edward E. Cohen, Jonathan Z. Cohen, and Sean P. McGrath and Freddie M. Kotek will initially devote a majority of his business time directly to our business or affairs, and Matthew A. Jones will initially devote substantially all of his business time directly to our business or affairs, provided that, in each case, this amount may increase or decrease in future periods. As such, we expect that a majority of Atlas Energy s compensation costs for its named executive officers in 2012 and beyond will be allocated to us, while a minority of Atlas Energy s compensation costs for its named executive officers will be allocated to Atlas Energy s other business divisions and affiliates (including Atlas Pipeline Partners, in each case which amounts may increase or decrease in future periods).

Employment Agreements

Certain individuals who serve as executive officers of our general partner (Edward E. Cohen, Jonathan Z. Cohen, and Matthew A. Jones) are party to employment agreements with Atlas Energy, which are described under Executive Compensation Atlas Energy Compensation Discussion and Analysis.

Compensation Philosophy and Objectives

As described above, we do not directly employ any of the persons responsible for managing our business. Our general partner manages our operations and activities using the employees of Atlas Energy and the board of directors and executive officers of our general partner and will make decisions on our behalf. All of the executive officers of our general partner (including Messrs. Edward E. Cohen, Jonathan Z. Cohen, Matthew A. Jones, Sean P. McGrath and Freddie M. Kotek) also serve as executive officers of Atlas Energy GP, LLC, the general partner of Atlas Energy. These shared officers will receive no additional salary, benefits or other cash compensation for their service to us. We also expect that future bonuses and other elements of compensation of our executive officers, including Messrs. Edward E. Cohen, Jonathan Z. Cohen, Matthew A. Jones, Sean P. McGrath and Freddie M. Kotek, will continue to be linked to performance metrics at Atlas Energy. The executive officer compensation plans and policies of Atlas Energy are described under Executive Compensation Atlas Energy Compensation Discussion and Analysis below. In addition, from time to time, the executive officers of our general partner may also receive awards of equity denominated in units of Atlas Resource Partners pursuant to the 2012 Atlas Resource Partners, L.P. Long-Term Incentive Plan described below. However, the board of directors of our general partner has not yet made any determination as to the number of awards, the type of awards or when the awards would be granted.

A full discussion of the compensation programs for Atlas Energy s named executive officers and the policies and philosophy of the compensation committee of the board of directors of Atlas Energy GP, LLC is set forth under Executive Compensation Atlas Energy Compensation Discussion and Analysis below.

2012 Long-Term Incentive Plan

Our 2012 Long-Term Incentive Plan is intended to promote the interests of us by providing to officers, employees and directors of our general partner, our general partner and employees of its affiliates, consultants and joint venture partners who perform services for our general partner or us (including employees of Atlas Energy and its general partner) incentive awards for superior performance that are based on our common units. The equity plan is intended to enhance the ability of our general partner and its affiliates to attract and retain the services of individuals who are essential for the growth and profitability of our general partner and us, and to encourage them to devote their best efforts to the businesses of our general partner and us.

Grants made under the equity plan will be determined by the board of directors of our general partner or a committee of the board of directors of our general partner, or the board (or a committee of the board) of an affiliate of our general partner that is appointed by the board of directors of our general partner to administer the new equity plan. We refer to the board of directors of our general partner, the board of an affiliate, or any respective committee thereof that administers the new equity plan as the committee.

Persons eligible to receive grants under the equity plan are (i) officers and employees of our general partner, its affiliates, consultants or joint venture partners who perform services for us, our general partner or an affiliate or in furtherance of our general partner s or our business (we refer to each such officer and employee as an eligible employee) and (ii) non-employee directors of our general partner within the meaning of Rule 16b-3 under the Exchange Act.

Awards in respect of up to 2.9 million of our common units may be issued under the equity plan. This amount is subject to adjustment as provided in the equity plan for events such as distributions (in our common units or other securities or property, including cash), unit splits (including reverse splits), recapitalizations, mergers, consolidations, reorganizations, reclassifications and other extraordinary events affecting our outstanding common units such that an adjustment is necessary in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the equity plan. Our common units issued under the equity plan may consist of our common units newly issued by us, our common units acquired in the open market or from any affiliate of our general partner or us or any other person or any combination of the foregoing. If any award granted under the equity plan is forfeited or otherwise terminates or is canceled or paid without the delivery of units, then the units covered by the award will (to the extent of the forfeiture, termination, or cancellation, as the case may be) again be available for grants of awards under the equity plan. Common units surrendered in payment of the exercise price of an option, and common units withheld or surrendered for payment of taxes, will not be available for re-issuance under the equity plan.

Awards granted under the new equity plan may consist of options to purchase our common units, phantom units and restricted units. All grants are subject to such terms and conditions as the committee deems appropriate, including but not limited to vesting conditions.

Options. An option is the right to purchase a common unit of ours in the future at a predetermined price (which we refer to as the exercise price). The exercise price of each option is determined by the committee and may be equal to or greater than the fair market value of a common unit on the date the option is granted. The committee will determine the vesting and exercise restrictions applicable to an award of options, if any, and the method or methods by which payment of the exercise price may be made, which may include, without limitation, cash, check acceptable to the board of directors of our general partner, a tender of common units having a fair market value equal to the exercise price, a cashless broker-assisted exercise, a recourse note in a form acceptable to the board of directors of our general partner and that does not violate the Sarbanes-Oxley Act of 2002, a net exercise that permits us to withhold a number of common units that otherwise would be issued to the holder of the option pursuant to the exercise of the option having a fair market value equal to the exercise price or any combination of the methods described above.

Phantom Units. Phantom units represent rights to receive a common unit of ours, an amount of cash or other securities or property based on the value of a common unit, or a combination of common units and cash or other securities or property. Phantom units are subject to terms and conditions determined by the committee, which may include vesting restrictions. In addition, the committee may grant distribution equivalent rights in connection with a grant of phantom units. Distribution equivalent rights represent the right to receive an amount in cash, securities, or other property equal to, and at the same time as, the cash distributions or other distributions of securities or other property made by us with respect to a common unit during the period that the underlying phantom unit is outstanding. Distribution equivalents may (i) be paid currently by us or may be deferred and, if deferred, may accrue interest, (ii) accrue as a cash obligation or may convert into additional phantom units for the holder of the underlying phantom units, (iii) be payable based on the achievement of specific goals and (iv) be payable in cash or our common units or in a combination of cash and common units, in each case as determined by the committee.

Restricted Units. Restricted units are actual common units of ours issued to a participant that are subject to vesting restrictions and evidenced in such manner as the committee may deem appropriate, including book-entry registration or issuance of one or more unit certificates. Prior to or upon the grant of an award of restricted units, the committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both. A holder of restricted units will have certain rights of holders of our common units in general, including the right to vote the restricted units. However, during the period during which the restricted units are subject to vesting restrictions, the holder will not be permitted to sell, assign, transfer, pledge or otherwise encumber the restricted units. As determined by the committee, cash dividends on restricted units may be automatically deferred or reinvested in additional restricted units and held subject to the vesting of the underlying restricted units, and dividends payable in our common units may be paid in the form of restricted units of the same class as the restricted units with respect to which the dividend is paid and may be subject to vesting of the underlying restricted units.

Upon a change in control (as defined in the equity plan), all unvested awards granted under the equity plan held by directors will immediately vest in full. In the case of awards granted under the equity plan held by eligible employees, upon the eligible employee s termination of employment without cause (as defined in the equity plan) or upon any other type of termination specified in the eligible employee s applicable award agreement(s), in any case following a change in control, any unvested award will immediately vest in full and, in the case of options, become exercisable for the one-year period following the date of termination of employment, but in any case not later than the end of the original term of the option.

In connection with a change in control, the committee, in its sole and absolute discretion and without obtaining the approval or consent of the unitholders or any participant, but subject to the terms of any award agreements and employment agreements to which our general partner (or any affiliate) and any participant are party, may take one or more of the following actions (with discretion to differentiate between individual participants and awards for any reason):

cause awards to be assumed or substituted by the surviving entity (or affiliate of such surviving entity);

accelerate the vesting of awards as of immediately prior to the consummation of the transaction that constitutes the change in control so that awards will vest (and, with respect to options, become exercisable) as to the common units that otherwise would have been unvested so that participants (as holders of awards granted under the new equity plan) may participate in the transaction;

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- provide for the payment of cash or other consideration to participants in exchange for the cancellation of outstanding awards (in an amount equal to the fair market value of such cancelled awards);

- terminate all or some awards upon the consummation of the change-in-control transaction, but only if the committee provides for full vesting of awards immediately prior to the consummation of such transaction; and

- make such other modifications, adjustments or amendments to outstanding awards or the new equity plan as the committee deems necessary or appropriate.

Except as otherwise determined by the committee, no award granted under the equity plan will be assignable or transferable except by will or the laws of descent and distribution. When a participant dies, the personal representative or other person entitled to succeed to the rights of the participant may exercise the participant s rights under his or her awards.

Director Compensation

The officers or employees of our general partner or of Atlas Energy or its general partner who also serve as directors of our general partner will not receive additional compensation for their service as a director of our general partner. Directors of our general partner who are not officers or employees of our general partner or of Atlas Energy or its general partner will receive compensation as set by our general partner s board of directors. Beginning in fiscal 2012, each non-employee director will receive cash compensation of $50,000 per year for service as a member of the board of directors of our general partner. The chairman of the audit committee will receive an annual fee of $15,000 per year and the chairman of the conflicts committee will receive an annual fee of $5,000 per year. Furthermore, each non-employee director will receive an annual grant of phantom units under the equity plan equal to $25,000 in value. These units will vest ratably over four years beginning on the grant date.

In addition, our general partner reimburses each non-employee director for out-of-pocket expenses in connection with attending meetings of the board or committees. We reimburse our general partner for these expenses and indemnify our general partner s directors for actions associated with serving as directors to the extent permitted by Delaware law.

Atlas Energy Compensation Discussion and Analysis

The following are excerpts from Atlas Energy s executive compensation disclosures that was included in Atlas Energy s Annual Report on Form 10-K for the fiscal year ended December 31, 2011. The following information is being included herein because Messrs. Edward E. Cohen, Jonathan Z. Cohen, Matthew A. Jones, Sean P. McGrath and Freddie M. Kotek, all of whom are executive officers of Atlas Energy s general partner, are also executive officers of our general partner. However, we and our general partner were recently formed, and Atlas Energy has not historically allocated the compensation of its executive officers to our business. Therefore, the following information, which presents executive compensation and related information for the named executive officers of Atlas Energy s general partner that are also executive officers of our general partner, is being presented so that it may be incorporated into the discussion under Executive Compensation Compensation Discussion and Analysis.

Overview

Prior to February 17, 2011, Atlas Energy was a controlled subsidiary of Atlas Energy, Inc. (which we sometimes refer to as AEI). On February 17, 2011, Chevron Corporation acquired AEI (which we refer to as the Chevron Merger), and immediately prior to the Chevron Merger, AEI distributed all of its common units in Atlas Energy so that Atlas Energy ceased to be a controlled subsidiary of AEI.

Before the consummation of the Chevron Merger, Atlas Energy did not directly compensate its executive officers. Rather, the AEI compensation committee was responsible for compensation decisions, and allocated the compensation of Atlas Energy s executive officers based upon an estimate of the time spent by such persons on activities for Atlas Energy s publicly traded subsidiary, Atlas Pipeline Partners, L.P. (which we refer to as APL), and for AEI and its other affiliates. APL reimbursed AEI for the compensation allocated to it; AEI did not make a separate allocation to Atlas Energy.

In February 2011, in connection with separating from AEI as a result of the Chevron Merger, Atlas Energy formed its own compensation committee, which is responsible for assisting Atlas Energy s board of directors in carrying out its responsibilities with respect to compensation. The committee is responsible for evaluating the compensation to be paid to

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Atlas Energy s CEO, CFO and the three other most highly-compensated executive officers, which Atlas Energy refers to as their Named Executive Officers or NEOs. The compensation committee is also responsible for administering Atlas Energy s employee benefit plans, including incentive plans. The compensation committee is comprised solely of independent directors, consisting of Ms. Ellen F. Warren and Messrs. Carlton Arrendell and Dennis Holtz, with Ms. Warren acting as the chairperson.

Compensation Objectives

Atlas Energy believes that its compensation program must support its business strategy, be competitive, and provide both significant rewards for outstanding performance and clear financial consequences for underperformance. Atlas Energy also believes that a significant portion of the NEOs compensation should be at risk in the form of annual and long-term incentive awards that are paid, if at all, based on individual and company accomplishment. Accounting and cost implications of compensation programs are considered in program design; however, the essential consideration is that a program is consistent with Atlas Energy s business needs.

Compensation Methodology

The compensation committee of Atlas Energy s general partner was formed in February 2011 and, at its initial meeting, recommended base salaries to be paid to its NEOs for its 2011 fiscal year. Going forward, Atlas Energy anticipates that the compensation committee will make its determination on compensation amounts shortly after the close of its fiscal year. In the case of base salaries, the committee will recommend the amounts to be paid for the new fiscal year. In the case of annual bonus and long-term incentive compensation, the committee will determine the amount of awards based on the most recently concluded fiscal year. Atlas Energy expects to pay cash awards and issue equity awards in February of each year, although the compensation committee has the discretion to recommend salary adjustments and the issuance of equity awards at other times during the fiscal year. In addition, Atlas Energy s NEOs and other employees who perform services for APL may receive stock-based awards from APL which has delegated compensation decisions to the compensation committee of Atlas Energy s general partner since APL does not currently have its own compensation committee.

Atlas Energy s Chief Executive Officer (CEO) provides the compensation committee with key elements of Atlas Energy s and the NEOs performance during the year. Atlas Energy s CEO makes recommendations to the compensation committee regarding the salary, bonus, and incentive compensation component of each NEO s total compensation. Atlas Energy s CEO, at the compensation committee s request, may attend committee meetings solely to provide insight into Atlas Energy s performance, as well as the performance of other comparable companies in the same industry.

Role of Compensation Consultant

Following the closing of the Chevron Merger, the compensation committee engaged Mercer (US) Inc., an independent compensation consulting firm, to provide market data for equity awards to be made to Atlas Energy s NEOs. As Atlas Energy was essentially reconstituted as a result of the acquisition of AEI s partnership management business and certain E&P assets, the compensation committee intended the awards to represent multi-year long-term incentive grants competitive with the 75th percentile of the market. In order to assist the committee in assessing the competitiveness of proposed awards, Mercer provided market data for long-term incentive grants to the 75th percentile from its 2010 oil and gas survey of data from 111 organizations. In addition, Mercer advised the compensation committee with respect to current employment agreement practices generally.

Elements of Atlas Energy s Compensation Program

Atlas Energy s executive officer compensation package generally includes a combination of annual cash and long-term incentive compensation. Annual cash compensation is comprised of base salary plus cash bonus. Long-term incentives consist of a variety of equity awards. Both the annual cash incentives and long-term incentives may be performance-based.

Base Salary

Base salary is intended to provide fixed compensation to the NEOs for their performance of core duties that contributed to Atlas Energy s success as measured by the elements of corporate performance mentioned above. Base salaries are not intended to compensate individuals for their extraordinary performance or for above average company performance.

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Annual Incentives

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

Performance-Based Bonuses In April 2011, the compensation committee adopted an Annual Incentive Plan for Senior Executives, which Atlas Energy refers to as the Senior Executive Plan, to award bonuses for achievement of predetermined, objective performance measures through the end of 2011. Awards under the Senior Executive Plan could be paid in cash or in a combination of cash and equity. Under the Senior Executive Plan, the maximum award payable to an individual was $15,000,000.

At the time the compensation committee adopted the Senior Executive Plan, it approved 2011 target bonus awards to be paid from a bonus pool. The bonus pool was equal to 18.3% of Atlas Energy s distributable cash flow unless the distributable cash flow included any capital transaction gains in excess of $50 million, in which case only 10% of that excess would be included in the bonus pool. If the distributable cash flow did not equal at least 80% of the 2011 budgeted distributable cash flow of $84,498,000, no bonuses would be paid. Distributable cash flow means the sum of (i) cash available for distribution by Atlas Energy, including its ownership interest in the distributable cash flow of any of its subsidiaries (regardless of whether such cash is actually distributed), plus (ii) to the extent not otherwise included in distributable cash flow, any realized gain on the sale of securities, including securities of a subsidiary, less (iii) to the extent not otherwise included in distributable cash flow, any loss on the sale of securities, including securities of a subsidiary. A return of Atlas Energy s capital investment in a subsidiary was not intended to be included and, accordingly, if distributable cash flow included proceeds from the sale of all or substantially all of the assets of a subsidiary, the amount of such proceeds to be included in distributable cash flow would be reduced by Atlas Energy s basis in the subsidiary.

The maximum award payable, expressed as a percentage of Atlas Energy s estimated 2011 distributable cash flow, for each participant was as follows: Edward E. Cohen, 6.14%; Jonathan Z. Cohen, 4.37%; Matthew A. Jones, 3.46% and Freddie Kotek, 1.73%. Sean McGrath did not participate in the Senior Executive Plan. Pursuant to the terms of the Senior Executive Plan, the compensation committee had the discretion to recommend reductions, but not increases, in awards under the Senior Executive Plan.

Discretionary Bonuses Discretionary bonuses may be awarded to recognize individual and group performance.

Long-Term Incentives

Atlas Energy believes that its long-term success depends upon aligning its executives and unitholders interests. To support this objective, Atlas Energy provides its executives with various means to become significant equity holders, including awards under its 2006 Long-Term Incentive Plan (the 2006 Plan) and its 2010 Long-Term Incentive Plan (the 2010 Plan), which Atlas Energy refers to as its Plans. Atlas Energy s NEOs are also eligible to receive awards under Atlas Pipeline Partners 2004 Long-Term Incentive Plan and its 2010 Long-Term Incentive Plan, which Atlas Energy refers to as the APL Plans.

Grants under Atlas Energy s Plans: Under Atlas Energy s Plans, the compensation committee may recommend grants of equity awards in the form of options and/or phantom units. Generally, the unit options and phantom units vest 25% on the third anniversary and 75% on the fourth anniversary of the date of grant.

Grants under Other Plans: As described above, Atlas Energy s NEOs who perform services for Atlas Energy and APL are eligible to receive unit-based awards under the APL Plans. In addition, Atlas Energy anticipates that some of its NEOs will be eligible to receive awards under ARP s long-term incentive plan.

Deferred Compensation

All of Atlas Energy s employees may participate in Atlas Energy s 401(k) plan, which is a qualified defined contribution plan designed to help participating employees accumulate funds for retirement. In July 2011, Atlas Energy established the Atlas Energy Executive Excess 401(k) Plan (the Excess 401(k) Plan), a non-qualified deferred compensation plan that is designed to permit individuals who exceed certain income thresholds and who may be subject to a compensation and/or contribution limitations under Atlas Energy s 401(k) plan to defer an additional portion of their

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compensation. The purpose of the Excess 401(k) Plan is to provide participants with an incentive for a long-term career with Atlas Energy by providing them with an appropriate level of replacement income upon retirement. Under the Excess 401(k) Plan, a participant may contribute to an account an amount up to 10% of annual cash compensation (which means a participant s salary and non-performance-based bonus) and up to all performance-based bonus. Atlas Energy is obligated to make matching contributions on a dollar-for-dollar basis of the amount deferred by the participant subject to a maximum matching contribution equal to 50% of the participant s base salary for any calendar year. The investment options under the Excess 401(k) Plan are substantially the same as the investment options under Atlas Energy s 401(k) plan; Atlas Energy does not pay above-market or preferential earnings on deferred compensation. Participation in the Excess 401(k) Plan is available pursuant to the terms of an individual s employment agreement or at the designation of the compensation committee. Currently, Messrs. E. Cohen and J. Cohen are the only participants in the Excess 401(k) Plan. For further details, please see the 2011 Non-Qualified Deferred Compensation table.

Post-Termination Compensation

Atlas Energy s NEOs received substantial cash amounts from Chevron in connection with the Chevron Merger, both as a result of the termination payments due under their employment agreements with AEI, which are described under Executive Compensation Atlas Energy Compensation Discussion and Analysis Employment Agreements and Potential Payments Upon Termination or Change of Control , and their equity holdings in AEI. Atlas Energy s compensation committee believed that the amounts thus realized left Atlas Energy s NEOs without adequate financial incentives to continue employment with Atlas Energy, which the committee did not believe was in Atlas Energy s interest as it moved forward with significant new operations. In order to encourage these executives to remain with Atlas Energy on a long-term basis, Atlas Energy made certain long-term incentive grants, which are described under Executive Compensation Atlas Energy Compensation Discussion and Analysis Elements of Atlas Energy s Compensation Program Long-Term Incentives , and entered into employment agreements with Messrs. E. Cohen, J. Cohen and Jones that, among other things, provide compensation upon termination of their employment by reason of death or disability, by Atlas Energy without cause or by each of them for good reason. See Executive Compensation Atlas Energy Compensation Discussion and Analysis Employment Agreements and Potential Payments Upon Termination or Change of Control . Good reason is defined under the agreements as:

- a material reduction in the executive s base salary;
- a demotion from the position held by the executive at the time the agreement was entered into;
- a material reduction in the executive s duties, it being deemed such a material reduction if Atlas Energy ceases to be a public company unless it becomes a subsidiary of a public company and, in the case of Mr. E. Cohen s agreement, he becomes the chief executive officer of the public parent, or, in the case of Mr. J. Cohen s agreement, he becomes an executive of the public parent with responsibilities substantially equivalent to his position, or, in the case of Mr. Jones s agreement, Atlas Energy s CEO or chairman of Atlas Energy s board are not, immediately following the transaction in which Atlas Energy ceases to be a public company, Atlas Energy s CEO or the CEO of the acquiring entity;
- the executive is required to relocate to a location more than 35 miles from his previous location;
- in the case of Messrs. E. and J. Cohen s agreements, he ceases to be elected to Atlas Energy s board; and
- any material breach of the agreement.

The compensation committee s rationale behind the design of the provisions of these agreements for termination by the executive for good cause are as follows:

Determination of Triggering Events The compensation committee elected not to include a change of control of Atlas Energy as a good reason triggering event and instead limited the triggering events to those (including after a change of control of Atlas Energy) where his position with Atlas Energy changes substantially and is essentially an involuntary termination.

Benefit Multiple The compensation committee determined the benefit multiple, that is, the cash severance amount based on each executive s salary and bonus, after consideration of comparable market practices provided to the committee by Mercer.

Perquisites

Atlas Energy provides limited perquisites to its NEOs at the discretion of the compensation committee. In 2011, these benefits were limited to providing cars to some NEOs and reimbursement of relocation expenses.

Determination of 2011 Compensation Amounts

Base Salary

In February 2011, the newly formed compensation committee of Atlas Energy s general partner approved the base salaries for our NEOs as follows: Mr. E. Cohen $700,000, Mr. McGrath $250,000, Mr. J. Cohen $500,000, Mr. Jones $280,000, and Mr. Kotek $280,000. These amounts matched or represented a decrease from their 2010 base salaries paid by AEI.

Annual and Transaction Incentives

The compensation committee was attentive to Atlas Energy s unique circumstances after the Chevron Merger, in that Atlas Energy had both completed a significant and transformative transaction and was re-establishing itself as a stand-alone entity. As part of the terms of the Chevron Merger, Chevron agreed that AEI could use $10 million for payments to key employees for retention bonuses and to reward performance, with approximately $3 million to be paid to key employees at or immediately prior to closing of the Chevron Merger and approximately $7 million (which was unallocated) to be transferred from AEI to Atlas Energy for allocation and payment by Atlas Energy to key employees following the Chevron Merger. Mr. McGrath was awarded a $900,000 retention bonus by the AEI compensation committee before he became Atlas Energy s Chief Financial Officer. While Atlas Energy s other NEOs did not receive any such retention bonuses from AEI, after the Chevron Merger, the compensation committee of Atlas Energy s general partner considered both individual and company performance of Atlas Energy s NEOs based upon their outstanding performance and leadership until the closing of the Chevron Merger and Atlas Energy s successful establishment as a stand-alone entity, and shortly after the closing of the Chevron Merger in February 2011 awarded cash bonuses to Messrs. E. Cohen, J. Cohen and Jones as follows: Mr. E. Cohen $2,500,000, Mr. J. Cohen $2,500,000, and Mr. Jones $1,250,000.

After the end of Atlas Energy s 2011 fiscal year, the compensation committee of Atlas Energy s general partner recommended incentive awards pursuant to the Senior Executive Plan based on the prior year s performance. In determining the actual amounts to be paid to the NEOs, the compensation committee considered both individual and company performance. Atlas Energy s CEO made recommendations of incentive award amounts based upon Atlas Energy s performance as well as the performance of Atlas Energy s subsidiaries; however, the compensation committee had the discretion to approve, reject, or modify the recommendations. The compensation committee noted that Atlas Energy s total unitholder return was 67% during 2011 and that Atlas Energy s cash distributions increased by approximately 600% over the prior year; Atlas Energy was able to reestablish its partnership fund raising programs despite the abbreviated sales period; Atlas Energy s management team worked throughout the year to prepare for the separation and distribution of Atlas Resource Partners from Atlas Energy, and successfully rebuilt Atlas Energy s operations team after the transfer of senior executives and technical staff to Chevron; Atlas Energy made fresh entries into the Marcellus Shale in areas not restricted by the non-competition agreements with Chevron, and increased Atlas Energy s drilling in Tennessee, Colorado and Ohio; and that APL had operated its plants at full capacity, declared distributions at a sharp increase from the prior year, continued to expand capacity and distributable cash flow through organic growth and enjoyed multiple credit rating upgrades. In addition, the compensation committee reviewed the calculations of Atlas Energy s distributable cash flow and determined that 2011 distributable cash flow exceeded the pre-determined minimum threshold of 80% of the budgeted distributable cash flow of $84,498,000. The compensation committee determined that based upon the strong performance of the NEOs as highlighted above, the bonuses for the NEOs were as follows: Mr. E. Cohen $3,500,000, Mr. J. Cohen $3,000,000, Mr. Jones $1,250,000, and Mr. Kotek $1,000,000. The bonuses awarded to the NEOs did not exceed 55% of the maximum bonus allocable to each NEO under the Senior Executive Plan formula, and were reduced in part in recognition of the cash bonus awards made in February for service until the date of such bonuses.

Mr. McGrath is not a participant in the Senior Executive Plan. The compensation committee of Atlas Energy s general partner awarded him a discretionary bonus of $375,000.

Long-Term Incentives

Immediately after the Chevron Merger, the compensation committee of Atlas Energy s general partner recognized that the leadership of Atlas Energy s NEOs was essential to Atlas Energy as it established itself as a stand-alone entity. It further concluded that strong incentive for Atlas Energy s NEOs to remain with Atlas Energy for a significant period of time and their close alignment with Atlas Energy s unitholders is critical in attracting and retaining additional key employees.

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However, the compensation committee further understood that Atlas Energy s NEOs had received substantial cash amounts from Chevron in connection with the Chevron Merger, both as a result of the termination payments due under their employment agreements with AEI, which are described under Executive Compensation Atlas Energy Compensation Discussion and Analysis Employment Agreements and Potential Payments Upon Termination or Change of Control , and their equity holdings in AEI, and that could have left Atlas Energy s NEOs without the adequate financial incentives to continue employment with Atlas Energy for a significant period of time, which the committee considered important. To provide such incentives and alignment, Atlas Energy made certain long-term incentive grants under Atlas Energy s 2010 Plan to its NEOs in March 2011 as follows: Mr. E. Cohen 300,000 phantom units and 700,000 options; Mr. McGrath 30,000 phantom units and 35,000 options; Mr. J. Cohen 250,000 phantom units and 500,000 options; Mr. Jones 150,000 phantom units and 200,000 options; and Mr. Kotek 30,000 phantom units and 70,000 options. (Mr. Kotek received an additional grant of 20,000 phantom units in April 2011 which brought his grant in line with the multiples of the other NEO grants described below.) The compensation committee intended the awards to represent multi-year long-term incentive grants competitive with the 75th percentile of the market. For each of the NEOs, consistent with Mercer s advice, the grants represented between 3.5 to 5.4 times the annual market long-term incentive level from Mercer s survey. The awards will vest 25% on the third anniversary of the grant and 75% on the fourth anniversary.

Summary Compensation Table

Name and principal position	Year	Salary ($)(1)	Bonus ($)	Unit awards ($)(2)	Option awards ($)(3)	Non-equity incentive plan compensation ($)	All other compensation ($)	Total ($)
Edward E. Cohen,	2011	746,154		6,669,000(5)	6,951,000(6)	3,500,000	3,066,906(7)	20,933,060
	2010	1,000,000		2,500,014	3,170,200	5,000,000	3,375	11,673,589
Chief Executive Officer and President(4)	2009	983,846				2,500,000	134,600	3,618,446
Sean P. McGrath, Chief Financial Officer(9)	2011	250,000	1,275,000	666,900(5)	347,550(6)		17,638(10)	2,557,088
Jonathan Z. Cohen,	2011	530,769		5,557,500(5)	4,965,000(6)	3,000,000	2,892,500(13)	16,945,769
Chairman of the Board	2010	700,000		2,000,005	3,170,000	4,000,000	1,688	9,871,693
	2009	676,923				2,000,000	88,163	2,765,086
Matthew A. Jones, Senior Vice President and President and Chief Operating Officer of E&P Division	2011	298,024		3,334,500(5)	1,986,000(6)	1,250,000	1,344,910(14)	8,213,434
Freddie M. Kotek, Senior Vice President of Investment Partnership Division	2011	298,462		1,170,900(5)	695,100(6)	1,000,000	37,774(15)	3,202,236

(1) The amounts in this column for Messrs. E. Cohen, J. Cohen, Jones and Kotek reflect amounts earned for a partial year of service with AEI and a partial year of service with Atlas Energy.

(2) The amounts reflect the grant date fair value of the phantom units under Atlas Energy s Plans and the APL Plans. The grant date fair value was determined in accordance with FASB ASC Topic 718, and is based on the market value on the grant date of Atlas Energy s units and APL s units.

(3) The amounts in this column reflect the grant date fair value of options awarded under Atlas Energy s Plans and the APL Plans calculated in accordance with FASB ASC Topic 718. Atlas Energy used the Black-Scholes option pricing model to estimate the weighted average fair value of the options. The following weighted average assumptions were used for the periods indicated:

	2011	2010	2009
Expected divided yield	1.50%	0.00%	6.20%
Expected stock price volatility	48.00%	48.00%	32.00%
Risk-free interest rate	2.83%	2.61%	2.25%
Expected term (in years)	6.875	6.250	6.458
Weighted average Black-Scholes value	$ 9.93	$ 14.41	$ 1.88

(4) On February 18, 2011, Mr. E. Cohen was appointed to serve in the capacity as Chief Executive Officer and President of Atlas Energy s general partner.

(5) In connection with Atlas Energy s establishment as a stand-alone entity following the Chevron Merger, the board approved awards of phantom units representing approximately four years worth of long-term incentive grants as follows: Mr. E. Cohen 300,000 phantom units; Mr. McGrath 30,000 phantom units; Mr. J. Cohen 250,000 phantom units; Mr. Jones 150,000 phantom units; and Mr. Kotek 50,000 phantom units. These grants will vest 25% on the third anniversary of the grant and 75% on the fourth anniversary of the grant.

(6) In connection with Atlas Energy s establishment as a stand-alone entity following the Chevron Merger, the board approved awards of options representing approximately four years worth of long-term incentive grants as follows: Mr. E. Cohen 700,000 options; Mr. McGrath 35,000 options; Mr. J. Cohen 500,000 options; Mr. Jones 200,000 options; and Mr. Kotek 70,000 options. These grants will vest 25% on the third anniversary of the grant and 75% on the fourth anniversary of the grant.

(7) Comprised of payments on DERs of $171,000 with respect to the phantom units awarded under Atlas Energy s Plans, $45,906 for an automobile made available for the use of Mr. E. Cohen (based on the purchase cost of the car and the cost of tax, title and insurance premiums), $2,500,000 transaction cash payment awarded February 2011, and matching contribution of $350,000 under the Excess 401(k) Plan.

(8) [Reserved]

(9) On February 18, 2011, Mr. McGrath was appointed to serve in the capacity of Chief Financial Officer of Atlas Energy s general partner.

(10) Comprised of payments on DERs of $17,100 with respect to the phantom units awarded under Atlas Energy s Plans and $538 with respect to the phantom units awarded under the APL Plans.

(11) [Reserved]

(12) [Reserved]

(13) Includes payments on DERs of $142,500 with respect to the phantom units awarded under Atlas Energy s Plans, transaction cash payment of $2,500,000 awarded in February 2011, and matching contribution of $250,000 under the Excess 401(k) Plan.

(14) Includes payments on DERs of $85,500 with respect to the phantom units awarded under Atlas Energy s Plans and a $1,250,000 transaction cash payment awarded in February 2011.

(15) Includes payments on DERs of $28,500 with respect to the phantom units awarded under Atlas Energy s Plans.

2011 Grants of Plan-Based Awards

	Estimated Possible Payments Under Non-Equity Incentive Plan Awards[1]							
Name	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Grant Date**	**All Other Stock Awards: Number of Shares of Stock or Units[2]**	**All Other Option Awards: Number of Securities Underlying Options[3]**	**Exercise of Base Price of Option Awards ($/Sh)[4]**	**Grant Date Fair Value of Unit and Option Awards ($)[5]**
Edward E. Cohen	N/A	N/A	7,673,000	3/25/11	300,000			6,669,000
				3/25/11		700,000	22.23	6,951,000
Sean P. McGrath	N/A	N/A	N/A	3/25/11	30,000			666,900
				3/25/11		35,000	22.23	347,550
Jonathan Z. Cohen	N/A	N/A	5,461,000	3/25/11	250,000			5,557,500
				3/25/11		500,000	22.23	4,965,000
Matthew A. Jones	N/A	N/A	4,332,000	3/25/11	150,000			3,334,500
				3/25/11		200,000	22.23	1,986,000
Freddie M. Kotek	N/A	N/A	2,166,000	3/25/11	30,000			666,900
				3/25/11		70,000	22.23	695,100
				4/27/11	20,000			504,000

(1) Represents performance-based bonuses under Atlas Energy s Senior Executive Plan. As discussed under Executive Compensation Atlas Energy Compensation Discussion and Analysis Elements of Atlas Energy s Compensation Program Annual Incentives Performance-Based Bonuses , the compensation committee set performance goals based on Atlas Energy s distributable cash flow and established maximum awards, but not minimum or target amounts, for each eligible NEO. Atlas Energy s Senior Executive Plan sets an individual limit of $15,000,000 per annum regardless of the maximum amounts that might otherwise be

payable.

(2) Represents phantom units granted under the 2010 Plan.

(3) Represents options granted under the 2010 Plan.

(4) The exercise price is equal to the closing price of Atlas Energy s common units on the date of grant.

(5) The grant date fair value was calculated in accordance with FASB ASC Topic 718.

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Employment Agreements and Potential Payments Upon Termination or Change of Control

Edward E. Cohen

2004 Employment Agreement

In May 2004, AEI entered into an employment agreement with Edward E. Cohen, who currently serves as Atlas Energy s Chief Executive Officer and President. The agreement was amended as of December 31, 2008 to comply with requirements under Section 409A of the Code relating to deferred compensation. As discussed above under Executive Compensation Atlas Energy Compensation Discussion and Analysis Overview , AEI allocated a portion of Mr. Cohen s compensation cost to APL based on an estimate of the time spent by Mr. Cohen on Atlas Energy s and APL s activities. AEI added 50% to the compensation amount allocated to APL to cover the costs of health insurance and similar benefits. Mr. Cohen s employment agreement terminated in February 2011 in connection with the Chevron Merger, and Atlas Energy entered into a new employment agreement with Mr. Cohen on May 13, 2011.

Mr. Cohen s employment agreement required him to devote such time to AEI as was reasonably necessary to the fulfillment of his duties, although it permitted him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $350,000 per year, which could be increased by the AEI compensation committee based upon its evaluation of Mr. Cohen s performance. Mr. Cohen was eligible to receive incentive bonuses and stock option grants and to participate in all employee benefit plans in effect during his period of employment.

The agreement had a term of three years and, until notice to the contrary, the term was automatically extended so that on any day on which the agreement was in effect it had a then-current three-year term. Mr. Cohen s former employment agreement was entered into in 2004, around the time that AEI was preparing to launch its initial public offering in connection with its spin-off from Resource America, Inc. At that time, it was important to establish a long-term commitment to and from Mr. Cohen as the Chief Executive Officer and then-current President of AEI. The rolling three-year term was determined to be an appropriate amount of time to reflect that commitment and was deemed a term that was commensurate with Mr. Cohen s position. The multiples of the compensation components upon termination or a change of control, discussed below, were generally aligned with competitive market practice for similar executives at the time that the agreement was negotiated.

The agreement provided the following regarding termination and termination benefits:

- Upon termination of employment due to death, Mr. Cohen s estate will receive (a) a lump sum payment in an amount equal to three times his final base salary and (b) automatic vesting of all stock and option awards.
- AEI may terminate Mr. Cohen s employment if he is disabled for 180 consecutive days during any 12-month period. If his employment is terminated due to disability, Mr. Cohen will receive (a) a lump sum payment in an amount equal to three times his final base salary, (b) a lump sum amount equal to the COBRA premium cost for continued health coverage, less the premium charge that is paid by AEI s employees, during the three years following his termination, (c) a lump sum amount equal to the cost AEI would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by AEI s employees, (d) automatic vesting of all stock and option awards and (e) any amounts payable under AEI s long-term disability plan.
- AEI may terminate Mr. Cohen s employment without cause, including upon or after a change of control, upon 30 days prior written notice. He may terminate his employment for good reason. Good reason is defined as a reduction in his base pay, a demotion, a material reduction in his duties, relocation, his failure to be elected to AEI s Board of Directors or AEI material breach of the agreement. Mr. Cohen must provide AEI with 30 days notice of a termination by him for good reason within 60 days of the event constituting good reason. AEI then would have 30 days in which to cure and, if it does not do so, Mr. Cohen s employment will terminate 30 days after the end of the cure period. If employment is terminated by AEI without cause, by Mr. Cohen for good reason or by either party in connection with a change of control, he will be entitled to either (a) if Mr. Cohen does not sign a release, severance benefits under AEI then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to three times his average compensation (defined as the average of the three highest years of total compensation), (ii) a lump sum amount equal to the COBRA premium cost for continued health coverage, less the premium charge that is paid by AEI employees, during the three years following his termination, (iii) a lump sum amount equal to the cost AEI would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by AEI employees, and (iv) automatic vesting of all stock and option awards.

Mr. Cohen may terminate the agreement without cause with 60 days notice to AEI, and if he signs a release, he will receive (a) a lump sum payment equal to one-half of one year s base salary then in effect and (b) automatic vesting of all stock and option awards.

Change of control was defined as:

the acquisition of beneficial ownership, as defined in the Securities Act, of 25% or more of AEI s voting securities or all or substantially all of AEI assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;

AEI consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) AEI s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless 1/2 of the surviving entity s board were AEI s directors immediately before the transaction and AEI; chief executive officer immediately before the transaction continues as the chief executive officer of the surviving entity; or (b) AEI s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of AEI, the surviving entity or, in the case of a division, each entity resulting from the division;

during any period of 24 consecutive months, individuals who were AEI Board members at the beginning of the period cease for any reason to constitute a majority of the AEI Board, unless the election or nomination for election by AEI s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or

AEI s stockholders approve a plan of complete liquidation or winding up of AEI, or agreement of sale of all or substantially all of AEI assets or all or substantially all of the assets of AEI s primary subsidiaries to an unaffiliated entity.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. In the event that any amounts payable to Mr. Cohen upon termination become subject to any excise tax imposed under Section 4999 of the Code, AEI must pay Mr. Cohen an additional sum such that the net amounts retained by Mr. Cohen, after payment of excise, income and withholding taxes, equals the termination amounts payable, unless Mr. Cohen s employment terminates because of his death or disability.

When Mr. Cohen s employment agreement terminated in February 2011, in connection with the Chevron Merger, he received the following, all of which was paid by Chevron: $60,354,581 for the cash-out of the AEI equity he held, $17,872,308 in severance, $71,842 in benefits payments; and $6,052,204 for excise tax gross-up.

2011 Employment Agreement

On May 13, 2011, Atlas Energy entered into a new employment agreement with Mr. Cohen to secure his service as President and Chief Executive Officer of Atlas Energy. The agreement has an effective date of May 16, 2011 and has a term of three years, which automatically renews daily, unless terminated before the expiration of the term pursuant to the termination provisions of the agreement.

The agreement provides for an initial annual base salary of $700,000, which may be increased at the discretion of the board of directors of Atlas Energy s general partner. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs and health and welfare plans and receive perquisites and reimbursement of business expenses, in each case as provided by Atlas Energy for its senior level executives generally. Mr. Cohen participates in the Excess 401(k) Plan, under which he may elect to defer up to 10% of his total annual cash compensation, which Atlas Energy must match on a dollar-for-dollar basis up to 50% of his annual base salary. See Executive Compensation Atlas Energy Compensation Discussion and Analysis 2011 Non-Qualified Deferred Compensation . During the term of the agreement, Atlas Energy must maintain a term life insurance policy on Mr. Cohen s life which provides a death benefit of $3 million, which can be assumed by Mr. Cohen upon a termination of employment.

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

Upon termination of employment due to death, all equity awards held by Mr. Cohen accelerate and vest in full upon the later of the termination of employment or six months after the date of grant of the awards (Acceleration of Equity Vesting), and Mr. Cohen s estate is entitled to receive, in addition to payment of all accrued and unpaid amounts of base salary, vacation, business expenses and other benefits (Accrued Obligations), a pro-rata bonus for the year of termination, based on the actual bonus that would have been earned had the termination of employment not occurred, determined and paid consistent with past practice (the Pro-Rata Bonus).

Atlas Energy may terminate Mr. Cohen s employment if he has been unable to perform the material duties of his employment for 180 days in any 12-month period because of physical or mental injury or illness, but Atlas Energy is required to pay his base salary until it acts to terminate his employment. Upon termination of employment due to disability, Mr. Cohen will receive the Accrued Obligations, all amounts payable under Atlas Energy s long-term disability plans, three years continuation of group term life and health insurance benefits (or, alternatively, Atlas Energy may elect to pay executive cash in lieu of such coverage in an amount equal to three years healthcare coverage at COBRA rates and the premiums Atlas Energy would have paid during the three-year period for such life insurance) (such coverage, the Continued Benefits), Acceleration of Equity Vesting, and the Pro-Rata Bonus.

Upon termination of employment by Atlas Energy without cause or by Mr. Cohen for good reason, Mr. Cohen will be entitled to either (i) if he does not execute and not revoke a release of claims against Atlas Energy, payment of the Accrued Obligations, or (ii), in addition to payment of the Accrued Obligations, if he executes and does not revoke a release of claims against Atlas Energy, (A) a lump-sum cash payment in an amount equal to three years of his average compensation (which is generally defined as the sum of (1) his base salary in effect immediately before the termination of employment plus (2) the average of the cash bonuses earned for the three calendar years preceding the year in which the date of termination of employment occurs (or $1,000,000 if the period of employment ended before the 2011 annual bonuses had been paid), (B) Continued Benefits, (C) the Pro-Rata Bonus, and (D) Acceleration of Equity Vesting.

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

Good reason is defined under the agreement as:

a material reduction in Mr. Cohen s base salary;

a demotion from his position;

a material reduction in Mr. Cohen s duties, it being deemed such a material reduction if Atlas Energy ceases to be a public company unless it becomes a subsidiary of a public company and Mr. Cohen becomes the chief executive officer of the public parent immediately following the applicable transaction;

Mr. Cohen is required to relocate to a location more than 35 miles from his previous location;

Mr. Cohen ceases to be elected to Atlas Energy s board; or

any material breach of the agreement.

Cause is defined as:

Mr. Cohen is convicted of a felony, or any crime involving fraud or embezzlement;

Mr. Cohen intentionally and continually fails to perform his reasonably assigned duties (other than as a result of disability), which failure is materially and demonstrably detrimental to Atlas Energy and has continued for 30 days after written notice signed by a majority of the independent directors of Atlas Energy s general partner; or

Mr. Cohen is determined, through arbitration, to have materially breached the restrictive covenants in the agreement.

In connection with a change of control, any excess parachute payments (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Cohen will be reduced such that the total payments to the executive which are subject to Internal Revenue Code Section 280G are no greater than the Section 280G safe harbor amount if he would be in a better after-tax position as a result of such reduction.

The following table provides an estimate of the value of the benefits to Mr. Cohen if a termination event had occurred as of December 31, 2011.

Reason for Termination	Lump Sum Severance Payment	Benefits[1]	Accelerated vesting of stock awards and option awards[2]
Death	$ 6,500,000[3]	$	$8,739,000
Disability	3,500,000	51,480	8,739,000
Termination by Atlas Energy without cause or by Mr. Cohen for good reason	5,100,000[4]	51,480	8,739,000

(1) Dental and medical benefits were calculated using 2011 COBRA rates.

(2) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table . The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2011. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2011.

(3) Includes the $3 million death benefit from the life insurance policy and payment of the 2011 bonus.

(4) Calculated based on Mr. Cohen s current base salary plus the applicable bonus.

Jonathan Z. Cohen

2009 Employment Agreement

In January 2009, AEI entered into an employment agreement with Jonathan Z. Cohen, who currently serves as Atlas Energy s Chairman. As discussed above under Executive Compensation Atlas Energy Compensation Discussion and Analysis Overview , AEI allocated a portion of Mr. Cohen s compensation cost based on an estimate of the time spent by Mr. Cohen on Atlas Energy s and APL s activities. Mr. Cohen s employment agreement terminated in February 2011 in connection with the Chevron Merger, and Atlas Energy entered into a new employment agreement with Mr. Cohen on May 13, 2011.

Mr. Cohen s employment agreement required him to devote such time to AEI as was reasonably necessary to the fulfillment of his duties, although it permitted him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $600,000 per year, which could be increased by the AEI board based upon its evaluation of Mr. Cohen s performance. Mr. Cohen was eligible to receive incentive bonuses and stock option grants and to participate in all employee benefit plans in effect during his period of employment. The agreement had a term of three years and, until notice to the contrary, the term was automatically extended so that on any day on which the agreement was in effect it had a then-current three-year term. The rolling three-year term and the multiples of the compensation components upon termination or a change of control, discussed below, were generally aligned with competitive market practice for similar executives at the time that the employment agreement was negotiated.

The agreement provided the following regarding termination and termination benefits:

Upon termination of employment due to death, Mr. Cohen s estate will receive (a) accrued but unpaid bonus and vacation pay and (b) automatic vesting of all equity-based awards.

AEI may terminate Mr. Cohen s employment without cause upon 90 days prior notice or if he is physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and AEI s board determines, in good faith based upon medical evidence, that he is unable to perform his duties. Upon termination by AEI other than for cause, including disability, or by Mr. Cohen for good reason (defined as any action or inaction that constitutes a material breach by AEI of the employment agreement or a change of control), Mr. Cohen will receive either (a) if Mr. Cohen does not sign a release, severance benefits under AEI s then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to three years of his average compensation (which is defined as his base salary in effect immediately before termination plus the average of the cash bonuses earned for the three calendar years preceding the year in which the termination occurred), less, in the case of termination by reason of disability, any amounts paid under disability insurance provided by AEI, (ii) monthly reimbursement of any COBRA premium paid by Mr. Cohen, less the amount Mr. Cohen would be required to contribute for health and dental coverage if he were an active employee and (iii) automatic vesting of all equity-based awards.

AEI may terminate Mr. Cohen s employment for cause (defined as a felony conviction or conviction of a crime involving fraud, deceit or misrepresentation, failure by Mr. Cohen to materially perform his duties after notice other than as a result of physical or mental illness, or violation of confidentiality obligations or representations contained in the employment agreement). Upon termination by AEI for cause or by Mr. Cohen for other than good reason, Mr. Cohen s vested equity-based awards will not be subject to forfeiture.

Change of control was defined as:

the acquisition of beneficial ownership, as defined in the Exchange Act, of 25% or more of AEI voting securities or all or substantially all of AEI s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;

- AEI consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) AEI s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless 1/2 of the surviving entity s board were AEI s directors immediately before the transaction and AEI s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) AEI s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of AEI, the surviving entity or, in the case of a division, each entity resulting from the division;
- during any period of 24 consecutive months, individuals who were AEI board members at the beginning of the period cease for any reason to constitute a majority of AEI s board, unless the election or nomination for election by AEI s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or
- AEI s stockholders approve a plan of complete liquidation or winding up, or agreement of sale of all or substantially all of AEI s assets or all or substantially all of the assets of its primary subsidiaries to an unaffiliated entity.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. When Mr. Cohen s employment agreement terminated in February 2011, in connection with the Chevron Merger, he received the following, all of which was paid by Chevron: $36,837,883 for the cash-out of the AEI equity he held and $8,600,000 in severance.

2011 Employment Agreement

On May 13, 2011, Atlas Energy entered into a new employment agreement with Mr. Cohen to secure his service as Chairman of the Board. The agreement has an effective date of May 16, 2011 and has a term of three years, which automatically renews daily, unless terminated before the expiration of the term pursuant to the termination provisions of the agreement.

The agreement provides for an initial annual base salary of $500,000, which may be increased at the discretion of the board of directors of Atlas Energy s general partner. Mr. Cohen is entitled to participate in any short-term and long-term incentive programs and health and welfare plans of Atlas Energy and receive perquisites and reimbursement of business expenses, in each case as provided by Atlas Energy for its senior level executives generally. Mr. Cohen participates in the Excess 401(k) Plan, under which he may elect to defer up to 10% of his total annual cash compensation, which Atlas Energy must match on a dollar-for-dollar basis up to 50% of his annual base salary. See Executive Compensation Atlas Energy Compensation Discussion and Analysis 2011 Non-Qualified Deferred Compensation . During the term of the agreement, Atlas Energy must maintain a term life insurance policy on Mr. Cohen s life which provides a death benefit of $2 million, which can be assumed by Mr. Cohen upon a termination of employment.

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

- Upon termination of employment due to death, all equity awards held by Mr. Cohen accelerate and vest in full upon the later of the termination of employment or six months after the date of grant of the awards (Acceleration of Equity Vesting), and Mr. Cohen s estate is entitled to receive, in addition to payment of all accrued and unpaid amounts of base salary, vacation, business expenses and other benefits (Accrued Obligations), a pro-rata bonus for the year of termination, based on the actual bonus that would have been earned had the termination of employment not occurred, determined and paid consistent with past practice (the Pro-Rata Bonus).
- Atlas Energy may terminate Mr. Cohen s employment if he has been unable to perform the material duties of his employment for 180 days in any 12-month period because of physical or mental injury or illness, but Atlas Energy is required to pay his base salary until it acts to terminate his employment.
- Upon termination of employment due to disability, Mr. Cohen will receive the Accrued Obligations, all amounts payable under Atlas Energy s long-term disability plans, three years continuation of group term life and health insurance benefits (or, alternatively, Atlas Energy may elect to pay executive cash in lieu of such coverage in an amount equal to three years healthcare coverage at COBRA rates and the premiums Atlas Energy would have paid during the three-year period for such life insurance) (such coverage, the Continued Benefits), Acceleration of Equity Vesting, and the Pro-Rata Bonus.
- Upon termination of employment by Atlas Energy without cause or by Mr. Cohen for good reason, Mr. Cohen will be entitled to either (i) if he does not execute and not revoke a release of claims against Atlas Energy, payment of the Accrued Obligations, or (ii), in addition to payment of the Accrued Obligations, if he executes and does not revoke a release of claims against Atlas Energy, (A) a lump-sum cash payment in an amount equal to three years of his average compensation (which is generally defined as the sum of (1) his base salary in effect immediately before the termination of employment plus (2) the average of the cash bonuses earned for the three calendar years preceding the year in which the date of termination of employment occurs (or $250,000 if the period of employment ended before the 2011 annual bonuses had been paid), (B) Continued Benefits, (C) the Pro-Rata Bonus, and (D) Acceleration of Equity Vesting.

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

Good reason is defined under the agreement as:

- a material reduction in Mr. Cohen s base salary;
- a demotion from his position;
- a material reduction in Mr. Cohen s duties, it being deemed such a material reduction if Atlas Energy ceases to be a public company unless Atlas Energy becomes a subsidiary of a public company and Mr. Cohen becomes an executive officer of the public parent with responsibilities substantially equivalent to his previous position immediately following the applicable transaction;
- Mr. Cohen is required to relocate to a location more than 35 miles from his previous location;
- Mr. Cohen ceases to be elected to Atlas Energy s board; or
- any material breach of the agreement.

Cause is defined as:

- Mr. Cohen is convicted of a felony, or any crime involving fraud or embezzlement;
- Mr. Cohen intentionally and continually fails to perform his reasonably assigned duties (other than as a result of disability), which failure is materially and demonstrably detrimental to Atlas Energy and has continued for 30 days after written notice signed by a majority of the independent directors of Atlas Energy s general partner; or
- Mr. Cohen is determined, through arbitration, to have materially breached the restrictive covenants in the agreement.

In connection with a change of control, any excess parachute payments (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Cohen will be reduced such that the total payments to the executive which are subject to Internal Revenue Code Section 280G are no greater than the Section 280G safe harbor amount if he would be in a better after-tax position as a result of such reduction.

The following table provides an estimate of the value of the benefits to Mr. Cohen if a termination event had occurred as of December 31, 2011.

Reason for Termination	Lump Sum Severance Payment	Benefits(1)	Accelerated vesting of stock awards and option awards(2)
Death	$ 5,000,000(3)	$	$7,110,000
Disability	3,000,000	74,210	7,110,000
Termination by Atlas Energy without cause or by Mr. Cohen for good reason	3,750,000(4)	74,210	7,110,000

(1) Dental and medical benefits were calculated using 2011 COBRA rates.
(2) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table . The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2011. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2011.
(3) Includes the $2 million death benefit from the life insurance policy and payment of the 2011 bonus.
(4) Calculated based on Mr. Cohen s current base salary plus the applicable bonus.

Matthew Jones

2009 Employment Agreement

In July 2009, AEI entered into an employment agreement with Matthew A. Jones, who served as its Chief Financial Officer. The agreement provided for initial base compensation of $300,000 per year, which provided that it may be increased at the discretion of AEI s Board of Directors. Mr. Jones was eligible to receive grants of equity based compensation from Atlas Energy, APL, and other affiliates, which we refer to as the Atlas Entities, and to participate in all employee benefit plans in effect during his period of employment. The agreement provided that any unvested equity compensation will be

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subject to forfeiture in accordance with the long-term incentive plan of the applicable entity except that, if AEI terminates Mr. Jones s employment without cause, including his disability, or if Mr. Jones terminates his employment for good reason or in the event of his death, all of his unvested awards will be fully vested.

The agreement had a term of two years. It provided that AEI may terminate the agreement:

- at any time for cause;
- without cause upon 90 days prior written notice;
- if Mr. Jones was physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and AEI s Board of Directors determines, in good faith based upon medical evidence, that he was unable to perform his duties; or
- in the event of Mr. Jones s death.

Mr. Jones had the right to terminate the agreement for good reason, defined as material breach by AEI of the agreement or a change of control. Mr. Jones must provide notice of a termination by him for good reason within 30 days of the event constituting good reason. AEI then would have 30 days in which to cure and, if it did not do so, Mr. Jones employment will terminate 30 days after the end of the cure period. Mr. Jones may also terminate the agreement without good reason upon 30 days notice. Termination amounts will not be paid until six months after the termination date, if such delay is required by Section 409A of the Internal Revenue Code.

Cause was defined as

- Mr. Jones having committed a demonstrable and material act of fraud;
- illegal or gross misconduct that is willful and results in damage to the business or reputation of the Atlas Entities;
- being charged with a felony;
- continued failure by Mr. Jones to perform his duties after notice other than as a result of physical or mental illness; or
- Mr. Jones failure to follow reasonable written directions consistent with his duties.

Good reason was defined as any action or inaction that constitutes a material breach by AEI of the agreement or a change of control.

Change of control was defined as:

- the acquisition of beneficial ownership, as defined in the Exchange Act, of 50% or more of AEI s voting securities or all or substantially all of AEI s assets by a single person or entity or group of affiliated persons or entities, other than by a related entity, defined as any of the Atlas Entities or any affiliate of AEI or of Mr. Jones or any member of his immediate family;
- the consummation of a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity, other than a related entity, in which either (a) AEI s directors immediately before the transaction constitute less than a majority of the board of directors of the surviving entity, unless 1/2 of the surviving entity s board were AEI s directors immediately before the transaction and AEI s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) AEI s voting securities immediately before the transaction represent less than 60% of the combined voting power immediately after the transaction of AEI, the surviving entity or, in the case of a division, each entity resulting from the division;
- during any period of 24 consecutive calendar months, individuals who were Board members at the beginning of the period cease for any reason to constitute a majority of the Board, unless the election or nomination for the election by AEI s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or
- AEI s stockholders approve a plan of complete liquidation or winding-up, or agreement of sale of all or substantially all of AEI s assets or all or substantially all of the assets of AEI s primary subsidiaries other than to a related entity.

The agreement provided the following regarding termination and termination benefits:

- upon termination of employment due to death, Mr. Jones designated beneficiaries would receive a lump sum cash payment within 60 days of the date of death of (a) any unpaid portion of his annual salary earned and not yet paid; (b) an amount representing the incentive compensation earned for the period up to the date of termination computed

by assuming that the amount of all such incentive compensation would be equal to the amount that Mr. Jones earned during the prior fiscal year, pro-rated through the date of termination; (c) any accrued but unpaid incentive compensation and vacation pay; and (d) all equity compensation awards would immediately vest.

upon termination by AEI for cause or by Mr. Jones for other than good reason, Mr. Jones would receive only base salary and vacation pay to the extent earned and not paid. Mr. Jones equity awards that have vested as of the date of termination would not be subject to forfeiture.

upon termination by AEI other than for cause, including disability, or by Mr. Jones for good reason, he would be entitled to either (a) if Mr. Jones did not sign a release, severance benefits under AEI s then current severance policy, if any, or (b) if Mr. Jones signed a release, (i) a lump sum payment in an amount equal to two years of his average compensation (which was defined as his base salary in effect immediately before termination plus the average of the cash bonuses earned for the three calendar years preceding the year in which the date of terminated occurred), less, in the case of termination by reason of disability, any amounts paid under disability insurance provided by AEI; (ii) monthly reimbursement of any COBRA premium paid Mr. Jones, less the amount Mr. Jones would be required to contribute for health and dental coverage if he were an active employee, for the 24 months following the date of termination, and (iii) automatic vesting of Mr. Jones equity awards.

When Mr. Jones employment agreement terminated in February 2011, in connection with the Chevron Merger, he received the following, all of which was paid by Chevron: $14,471,906 for the cash-out of the AEI equity he held and $3,400,000 in severance.

2011 Employment Agreement

In November 2011, Atlas Energy entered into an employment agreement with Matthew A. Jones. Under the agreement, Mr. Jones has the title of Senior Vice President and President and Chief Operating Officer of the Exploration and Production Division of Atlas Energy. The agreement has an effective date of November 4, 2011 and has an initial term of two years, which automatically ends at the end of such initial two-year term unless Atlas Energy elects to renew the agreement for a subsequent two-year term pursuant to the agreement.

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

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

Upon a termination by Atlas Energy for cause or by Mr. Jones without good reason, he is entitled to receive payment of accrued but unpaid base salary and (to the extent required to be paid under Atlas Energy policy) amounts of accrued but unpaid vacation, in each through the date of termination (together, the Accrued Obligations).

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

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

- if Mr. Jones does not timely execute (or revokes) a release of claims against Atlas Energy, payment of the Accrued Obligations and payment of the Pro-Rata Bonus; or
- in addition to payment of the Accrued Obligations and payment of the Pro-Rata Bonus, if Mr. Jones timely executes and does not revoke a release of claims against Atlas Energy:
  - a lump-sum cash severance payment in an amount equal to two years of his average compensation (which is the sum of his then-current base salary and the average of the cash bonuses earned for the three calendar years preceding the year in which the termination occurs);
  - healthcare continuation at active employee rates for two years; and
  - Acceleration of Equity Vesting.

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Good reason is defined under the agreement as:

- a material reduction in Mr. Jones base salary;
- a demotion from his position;
- a material reduction in Mr. Jones duties, it being deemed such a material reduction if Atlas Energy ceases to be a public company unless Atlas Energy become a subsidiary of a public company and Atlas Energy s CEO or the Chairman of Atlas Energy s general partner s board is not Atlas Energy s CEO or the CEO of the acquiring entity;
- Mr. Jones is required to relocate to a location more than 35 miles from his previous location; or
- any material breach of the agreement.

Cause is defined as:

- Mr. Jones has committed any demonstrable and material fraud;
- illegal or gross misconduct by Mr. Jones that is willful and results in damage to Atlas Energy s business or reputation;
- Mr. Jones is convicted of a felony, or any crime involving fraud or embezzlement;
- Mr. Jones fails to substantially perform his duties (other than as a result of disability) after written demand and a reasonable opportunity to cure; or
- Mr. Jones fails to follow reasonable written instructions which are consistent with his duties.

In connection with a change of control of Atlas Energy, any excess parachute payments (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Jones will be reduced such that the total payments to the executive which are subject to Section 280G are no greater than the Section 280G safe harbor amount if Mr. Jones would be in a better after-tax position as a result of such reduction.

The following table provides an estimate of the value of the benefits to Mr. Jones if a termination event had occurred as of December 31, 2011.

Reason for Termination	**Lump Sum Severance Payment**	**Benefits[(1)]**	**Accelerated vesting of stock awards and option awards[(2)]**
Death	$ 1,250,000	$ 17,255	$4,059,000
Disability	1,250,000		4,059,000
Termination by Atlas Energy without cause or by Mr. Jones for good reason	560,000[(3)]	34,510	4,059,000

(1) Dental and medical benefits were calculated using 2011 active employee rates.

(2) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table . The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2011. The payments relating to awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2011.

(3) Calculated based on Mr. Jones s 2011 base salary.

Atlas Energy s Long-Term Incentive Plans

Atlas Energy s 2006 Plan

Atlas Energy s 2006 Plan provides equity incentive awards to officers, employees and board members and employees of Atlas Energy s general partner and its affiliates, consultants and joint-venture partners who perform services for Atlas Energy. Atlas Energy s 2006 Plan is administered by the board of Atlas Energy s general partner or the board of an affiliate appointed by Atlas Energy s general partner s board (the Committee). The Committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 common limited partner units. Pursuant to the employee matters agreement Atlas Energy entered into in connection with the sale of assets from AEI to Atlas Energy on February 17, 2011 (the AHD Transactions), Atlas Energy amended its 2006 Plan to provide that outstanding awards granted under the 2006 Plan did not vest in connection with the Chevron Merger and the AHD Transactions pursuant to the terms and conditions of the 2006 Plan.

Partnership Phantom Unit. A phantom unit entitles a participant to receive a common unit upon vesting of the phantom unit. Beginning with the fiscal year 2010, non-employee directors receive an annual grant of phantom units, which upon vesting entitles the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. The phantom units vest over four years. In tandem with phantom unit grants, the Committee may grant a DER. The Committee determines the vesting period for phantom units. Phantom units granted under Atlas Energy s 2006 Plan generally vest 25% on the third anniversary of the date of grant, with the remaining 75% vesting on the fourth anniversary of the date of grant, except non-employee director grants vest 25% per year.

Partnership Unit Options. A unit option entitles a participant to receive a common unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option may be equal to or more than the fair market value of a common unit as determined by the Committee on the date of grant of the option. The Committee determines the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Unit options granted generally will vest 25% on the third anniversary of the date of grant, with the remaining 75% vesting on the fourth anniversary of the date of grant.

Atlas Energy s 2010 Plan

Atlas Energy s 2010 Plan provides equity incentive awards to officers, employees and board members and employees of Atlas Energy s general partner and its affiliates, consultants and joint-venture partners who perform services for Atlas Energy. Atlas Energy s 2010 Plan is administered by the Committee and the Committee may grant awards of either phantom units, unit options or restricted units for an aggregate of 5,300,000 common limited partner units.

Partnership Phantom Units. A phantom unit entitles a participant to receive a common unit upon vesting of the phantom unit. Beginning in fiscal year 2010, non-employee directors receive an annual grant of phantom units, which upon vesting, entitles the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. The phantom units vest over four years. In tandem with phantom unit grants, the Committee may grant a DER. The Committee determines the vesting period for phantom units.

Partnership Unit Options. A unit option entitles a participant to receive a common unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option may be equal to or more than the fair market value of a common unit as determined by the Committee on the date of grant of the option. The Committee determines the vesting and exercise period for unit options.

Partnership Restricted Units. A restricted unit is a common unit issued that entitles a participant to receive it upon vesting of the restricted unit. Prior to or upon grant of an award of restricted units, the Committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both.

Upon a change in control, as defined in the 2010 Plan, all unvested awards held by directors will immediately vest in full. In the case of awards held by eligible employees, upon the eligible employee s termination of employment without cause , as defined in the 2010 Plan, or upon any other type of termination specified in the eligible employee s applicable award agreement(s), in any case following a change in control, any unvested award will immediately vest in full and, in the case of options, become exercisable for the one-year period following the date of termination of employment, but in any case not later than the end of the original term of the option.

APL Plans

The APL 2004 Long-Term Incentive Plan (the 2004 APL Plan) and the 2010 Long-Term Incentive Plan, which was modified in April 2011 (the 2010 APL Plan and collectively with the 2004 APL Plan the APL Plans) provide incentive awards to officers, employees and non-employee managers of Atlas Pipeline GP and officers and employees of its affiliates, consultants and joint venture partners who perform services for APL or in furtherance of its business. The APL Plans are administered by Atlas Pipeline GP s managing board or the board of an affiliate appointed by it (the APL Committee). Under the APL Plans, the APL Committee may make awards of either phantom units or options covering an aggregate of 435,000 common units under the 2004 APL Plan and 3,000,000 common units under the 2010 APL Plan.

APL Phantom Units. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit. In addition, the compensation committee may grant a participant the right, which is referred to as a DER, to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions are made on an APL common unit during the period the phantom unit is outstanding.

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APL Unit Options. An option entitles the grantee to purchase APL common units at an exercise price determined by the compensation committee, which may be less than, equal to or more than the fair market value of APL common units on the date of grant. The compensation committee will also have discretion to determine how the exercise price may be paid.

Except for phantom units awarded to non-employee managers of Atlas Pipeline GP, the APL Committee will determine the vesting period for phantom units and the exercise period for options. Phantom units awarded to non-employee managers will generally vest over a 4-year period at the rate of 25% per year. Both types of awards will automatically vest upon a change of control, as defined in the APL Plans.

2011 Outstanding Equity Awards at Fiscal Year-End Table

	Option Awards				Stock Awards	
Name	**Exercisable**	**Unexercisable**	**Option Exercise price ($)**	**Option Expiration Date**	**Number of Units that have not Vested (#)**	**Market Value of Units that have not Vested ($)**
Edward E. Cohen	500,000(1)		22.56	11/10/2016		
		700,000(2)	22.23	3/25/2021	300,000(3)	7,290,000
Sean P. McGrath	15,000(1)		22.56	11/10/2016		
			N/A	N/A	250(6)	9,288
		35,000(7)	22.23	3/25/2021	30,000(8)	729,000
Jonathan Z. Cohen	200,000(1)		22.56	11/10/2016		
		500,000(9)	22.23	3/25/2021	250,000(10)	6,075,000
Matthew A. Jones	100,000(1)		22.56	11/10/2016		
		200,000(11)	22.23	3/25/2021	150,000(12)	3,645,000
Freddie M. Kotek		70,000(13)	22.23	3/25/2021	30,000(14)	729,000
			N/A	N/A	20,000(15)	486,000

(1) Represents options to purchase Atlas Energy s units.
(2) Represents options to purchase Atlas Energy s units, which vest as follows: 3/25/2014 175,000 and 3/25/2015 525,000.
(3) Represents Atlas Energy s phantom units, which vest as follows: 3/25/2014 75,000 and 3/25/2015 225,000.
(4) [Reserved]
(5) [Reserved]
(6) Represents APL phantom units, which vest on 2/13/2012.
(7) Represents options to purchase Atlas Energy s units, which vest as follows: 3/25/2014 8,750 and 3/25/2015 26,250.
(8) Represents Atlas Energy s phantom units, which vest as follows: 3/25/2014 7,500 and 3/25/2015 22,500.
(9) Represents options to purchase Atlas Energy s units, which vest as follows: 3/25/2014 125,000 and 3/25/2015 375,000.
(10) Represents Atlas Energy s phantom units, which vest as follows: 3/25/2014 62,500 and 3/25/2015 187,500.
(11) Represents options to purchase Atlas Energy s units, which vest as follows: 3/25/2014 50,000 and 3/25/2015 150,000.
(12) Represents Atlas Energy s phantom units, which vest as follows: 3/25/2014 37,500 and 3/25/2015 112,500.
(13) Represents options to purchase Atlas Energy s units, which vest as follows: 3/25/2014 17,500 and 3/25/2015 52,500.
(14) Represents Atlas Energy s phantom units, which vest as follows: 3/25/2014 7,500 and 3/25/2015 22,500.
(15) Represents Atlas Energy s phantom units, which vest as follows: 4/27/2014 5,000 and 4/27/2015 15,000.

2011 Option Exercises and Units Vested Table

		Option Awards			Unit Awards		
Name	**Number of**	**Value Realized**	**Value from Cash Payout ($)**	**Number of**	**Value**	**Value from**	**Total Value ($)**

	Units Acquired on Exercise	on Exercise ($)	Units Acquired on Vesting	Realized on Vesting ($)	Cash Payout ($)	
Edward E. Cohen	[1]	57,398,850	195,514[2]	2,729,066	2,955,731	63,083,647
Sean P. McGrath	[5]	903,051	8,950	128,017		1,031,068
Jonathan Z. Cohen	[7]	34,473,307	104,211[8]	1,457,148	2,364,576	38,295,031
Matthew A. Jones	[9]	13,526,060	24,284[10]	340,819	945,846	14,812,725
Freddie M. Kotek	[11]	8,094,560	21,703[12]	303,782	591,116	8,989,458

(1) Pursuant to the terms of the Chevron Merger agreement, 2,112,500 AEI options were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration less the exercise price, which amount is shown in the Value from Cash Payout column.
(2) Does not include 77,274 units that, pursuant to the terms of the Chevron Merger agreement, were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration which amount is shown in the Value from Cash Payout column.
(3) [Reserved]
(4) [Reserved]
(5) Pursuant to the terms of the Chevron Merger agreement, 47,050 AEI options were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration less the exercise price, which amount is shown in the Value from Cash Payout column.
(6) [Reserved]
(7) Pursuant to the terms of the Chevron Merger agreement, 1,322,000 AEI options were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration less the exercise price, which amount is shown in the Value from Cash Payout column.
(8) Does not include 61,819 units that, pursuant to the terms of the Chevron Merger agreement, were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration which amount is shown in the Value from Cash Payout column.
(9) Pursuant to the terms of the Chevron Merger agreement, 518,000 AEI options were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration less the exercise price, which amount is shown in the Value from Cash Payout column.
(10) Does not include 24,728 units that, pursuant to the terms of the Chevron Merger agreement, were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration which amount is shown in the Value from Cash Payout column.
(11) Pursuant to the terms of the Chevron Merger agreement, 323,000 AEI options were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration less the exercise price, which amount is shown in the Value from Cash Payout column.
(12) Does not include 15,454 units that, pursuant to the terms of the Chevron Merger agreement, were cancelled before the effective time of the Chevron Merger and converted into a right to receive the merger consideration which amount is shown in the Value from Cash Payout column.

2011 Non-Qualified Deferred Compensation

Name	Executive Contributions in the Last FY ($)	Registrant Contributions in the Last FY ($)	Aggregate Earnings in the Last FY ($)	Aggregate Balance at Last FYE ($)
Edward E. Cohen	350,000(1)	350,000(3)	561	700,561
Jonathan Z. Cohen	250,000(2)	250,000(4)	400	500,400

(1) This amount is included within the Summary Compensation Table for 2011 reflecting $70,000 in the salary column and $280,000 in the non-equity incentive plan compensation column.
(2) This amount is included within the Summary Compensation Table for 2011 reflecting $50,000 in the salary column and $200,000 in the non-equity incentive plan compensation column.
(3) This amount is included within the Summary Compensation Table for 2011 reflecting our $350,000 matching contribution in the All Other Compensation column.
(4) This amount is included within the Summary Compensation Table for 2011 reflecting our $250,000 matching contribution in the All Other Compensation column.

Effective July 1, 2011, Atlas Energy established the Excess 401(k) Plan, an unfunded nonqualified deferred compensation plan for certain highly compensated employees. The Excess 401(k) Plan provides Messrs. E. and J. Cohen, the plan s current participants, with the opportunity to defer, annually, the receipt of a portion of their compensation, and to permit them to designate investment indices for the purpose of crediting earnings and losses on any amounts deferred under the Excess 401(k) Plan. Messrs. E. and J. Cohen may defer up to 10% of their total annual cash compensation (which includes base salary and non-performance-based bonus) and up to all performance-based bonus, and Atlas Energy is obligated to match such deferrals on a dollar-for-dollar basis (i.e., 100% of the deferral) up to a total of 50% of their base salary for any calendar year. The account is invested in a mutual fund and cash balances are invested daily in a money market account. Atlas Energy established a rabbi trust to serve as the funding vehicle for the Excess 401(k) Plan and Atlas Energy will, not later than the last day of the first month of each calendar quarter, make contributions to the trust in the amount of the compensation deferred, along with the corresponding match, during the preceding calendar quarter. Notwithstanding the establishment of the rabbi trust, Atlas Energy s obligation to pay the amounts due under the Excess 401(k) Plan constitutes a general, unsecured obligation, payable out of Atlas Energy s general assets, and Messrs. E. and J. Cohen do not have any rights to any specific asset of Atlas Energy.

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The Excess 401(k) Plan has the following additional provisions:

At the time the participant makes his deferral election with respect to any year, he must specify the date or dates (but not more than two) on which distributions will start, which date may be upon termination of employment or a date that is at least three years after the year in which the amount deferred would otherwise have been earned. A participant may subsequently defer a specified payment date for a minimum of an additional five years from the previously elected payment date. If the participant fails to make an election, all amounts will be distributable upon the termination of employment.

Distributions will be made earlier in the event of death, disability or a termination of employment due to a change of control.

If the participant elects to receive all or a portion of his distribution upon the termination of employment, it will be paid in a lump sum. Otherwise, the participant may elect to receive a lump sum payment or equal installments over not more than 10 years.

A participant may request a distribution of all or part of his account in the event of an unforeseen financial emergency. An unforeseen financial emergency is a severe financial hardship due to an unforeseeable emergency resulting from a sudden and unexpected illness or accident of the participant, or, a sudden and unexpected illness or accident of a dependent, or loss of the participant s property due to casualty, or other similar and extraordinary unforeseeable circumstances arising as a result of events beyond the control of the participant. An unforeseen financial emergency is not deemed to exist to the extent it is or may be relieved through reimbursement or compensation by insurance or otherwise; by borrowing from commercial sources on reasonable commercial terms to the extent that this borrowing would not itself cause a severe financial hardship; by cessation of deferrals under the plan; or by liquidation of the participant s other assets (including assets of the participant s spouse and minor children that are reasonably available to the participant) to the extent that this liquidation would not itself cause severe financial hardship.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Before the separation and distribution, all of our outstanding common units, representing a 98% limited partner interest, were owned beneficially and of record by Atlas Energy, and all of our outstanding class A units, representing a 2% general partner interest, were owned beneficially and of record by Atlas Resource Partners GP, LLC, which is wholly owned by Atlas Energy. After the distribution, Atlas Energy retained ownership of approximately 20.96 million common units, representing 80% of the outstanding common units and an approximately 78.4% limited partner interest. In addition, Atlas Energy continues to own 100% of the equity of our general partner, Atlas Resource Partners GP, LLC, which, in turn, owns 534,694 class A units, representing a 2% general partner interest, and all of our incentive distribution rights.

The following table provides information with respect to the beneficial ownership of our common units as of March 26, 2012 by (1) each person who is known by us who beneficially owns more than 5% of our common units, (2) each member of the board of directors of our general partner, (3) each executive officer of our general partner, and (4) all of the executive officers and members of the board of directors of our general partner. Except as otherwise noted in the footnotes below, each person or entity identified below has sole voting and investment power with respect to such securities.

The address of each director and executive officer shown in the table below is c/o Atlas Resource Partners GP, LLC, Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, PA 15275.

Beneficial owner	Beneficial Ownership of Common Units	Percent of Common Units	Percentage Interest in Partnership
5% Unitholders			
Atlas Energy, L.P.[1]	20,962,485	80%	78.4%
Directors			
Edward E. Cohen	149,395(2)	*	*
Jonathan Z. Cohen	136,849(3)	*	*
Matthew A. Jones	3,273	*	*
Anthony Coniglio		*	*
DeAnn Craig	449	*	*

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Beneficial owner	Beneficial Ownership of Common Units	Percent of Common Units	Percentage Interest in Partnership
Jeffrey C. Key		*	*
Bruce Wolf	9,485	*	*
Non-Director Executive Officers			
Sean P. McGrath	1,070	*	*
Freddie M. Kotek	1,700	*	*
Jeffrey M. Slotterback	31	*	*
Lisa Washington	366	*	*
All Executive Officers and Directors as a Group (11 persons)	302,618	1.16%	1.13%

* Less than 1%

(1) The address of Atlas Energy, L.P. is Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, PA 15275.

(2) Includes (i) 5,881 units held in an IRA for Edward Cohen; (ii) 2,680 units held in an IRA account of Mrs. Betsy Cohen (the wife of Edward Cohen and mother of Jonathan Cohen); (iii) 5,346 units owned by the Solomon Investment Partnership (Edward Cohen and Mrs. Cohen are the sole limited partners of the Solomon Investment Partnership); (iv) 120,342 units owned by the Arete Foundation (the trustees of the Arete Foundation are Edward Cohen, Mrs. Cohen, Daniel G. Cohen (the son of Edward Cohen and Mrs. Cohen) and Jonathan Cohen); (v) 7,510 units owned by the Edward E. Cohen Trust U/A/O October 7, 1999 (Edward Cohen is the settlor of the trust, Mrs. Cohen is a trustee of the trust, and Mrs. Cohen is the beneficiary of the trust); (vi) 6,868 units owned by the Betsy Z. Cohen Trust U/A/O October 7, 1999 (Mrs. Cohen is the settlor of the trust and Daniel G. Cohen and Jonathan Cohen are each trustees and beneficiaries of the trust); and (vii) 766 units owned by the 2010 Cohen Family Trust (Edward Cohen is the settlor of the trust, Mrs. Cohen is a contingent trustee, and each of Mrs. Cohen, Daniel G. Cohen, and Jonathan Cohen are beneficiaries of the trust). Edward Cohen disclaims beneficial ownership of any units described above in (ii), (iii), (iv), (v), (vi) and (vii).

(3) Includes (i) 9,638 units jointly owned by Jonathan Cohen and Julia Pershan Cohen (the wife of Jonathan Cohen), (ii) 120,342 units owned by the Arete Foundation (the trustees of the Arete Foundation are Edward Cohen, Mrs. Cohen, Daniel G. Cohen (the son of Edward Cohen and Mrs. Cohen) and Jonathan Cohen) and (iii) 6,868 units owned by the Betsy Z. Cohen Trust U/A/O October 7, 1999 (Mrs. Cohen is the settlor of the trust and Daniel G. Cohen and Jonathan Cohen are each trustees and beneficiaries of the trust). Jonathan Cohen disclaims beneficial ownership of any units described above in (ii) and (iii).

Equity Compensation Plan Information

On March 19, 2012, while we were still a wholly-owned subsidiary of Atlas Energy, we adopted, with the approval of Atlas Energy, our 2012 Long-term Incentive Plan. The following table contains information about the plan:

Plan category	Number of securities to be issued upon exercise of equity instruments (a)	Weighted-average exercise price of outstanding equity instruments (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			2,900,000
Equity compensation plans not approved by security holders			
Total			2,900,000

The following table contains information about Atlas Energy s 2006 Plan as of December 31, 2011:

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Plan category		Number of securities to be issued upon exercise of equity instruments (a)	Weighted-average exercise price of outstanding equity instruments (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	phantom units	32,641	n/a	
Equity compensation plans approved by security holders	options	903,614	$21.52	
Total		936,255		922,871

The following table contains information about Atlas Energy s 2010 Plan as of December 31, 2011:

Plan category		Number of securities to be issued upon exercise of equity instruments (a)	Weighted-average exercise price of outstanding equity instruments (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	phantom units	1,838,164	n/a	
Equity compensation plans approved by security holders	unit options	2,304,300	$22.12	
Total		4,142,464		1,157,536

The following table contains information about the APL s 2004 Plan as of December 31, 2011:

Plan category		Number of securities to be issued upon exercise of equity instruments (a)	Weighted-average exercise price of outstanding equity instruments (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	phantom units	12,585	n/a	
Equity compensation plans approved by security holders	unit options		n/a	
Total		12,585		66,709

The following table contains information about the APL s 2010 Plan as of December 31, 2011:

Plan category		Number of securities to be issued upon exercise of equity instruments (a)	Weighted-average exercise price of outstanding equity instruments (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	phantom units	381,904	n/a	
Equity compensation plans approved by security holders	unit options		n/a	
Total		381,904		2,297,570

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE
Our Relationship with Atlas Energy and Atlas Resource Partners GP, LLC

Immediately following the March 2012 separation and distribution, Atlas Energy owns approximately 20.96 million of our outstanding common units, representing 80% of the outstanding common units and an approximately 78.4% limited partner interest. In addition, Atlas Energy owns all of the equity of our general partner, Atlas Resource Partners GP, LLC. Our general partner will own 534,694 class A units, representing a 2% general partner interest, and all of our incentive distribution rights. As the owner of our incentive distribution rights, our general partner will be entitled to receive increasing percentages, up to a maximum of 50%, of any cash distributed by us as it reaches certain target distribution levels in excess of $0.46 per common unit of Atlas Resource Partners in any quarter.

We are required by our partnership agreement to distribute all of our available cash, as defined in our partnership agreement, at the end of each quarter. Available cash is generally defined to include all our cash on hand at the end of any quarter, less reserves established by our general partner, in its sole discretion to provide for the proper conduct of our business or to provide for future distributions. Our general partner will be reimbursed for direct and indirect expenses incurred on our behalf. Some of the non-independent directors of our general partner also serve as directors of Atlas Energy s general partner.

We do not currently directly employ any persons to manage or operate our business. These functions are provided by employees of Atlas Energy and/or its affiliates. Our general partner does not receive a management fee in connection with its management of us apart from its class A units in us and its right to receive incentive distributions. We reimburse our general partner and its affiliates, including Atlas Energy, for expenses they incur in managing our operations and for an allocation of the compensation paid to the executive officers of its general partner, based upon an estimate of the time spent by such persons on activities for us. Other indirect costs, such as rent for offices, are allocated to us by Atlas Energy based on the number of its employees who devote substantially all of their time to activities on our behalf. We reimburse Atlas Energy at cost for direct costs incurred by them on our behalf. Our partnership agreement provides that our general partner will determine the costs and expenses that are allocable to us at its sole discretion, and does not set any aggregate limit on the amount of such reimbursements.

In connection with the acquisition of Old Atlas by Chevron Corporation in February 2011, Jonathan Cohen, who serves as Chairman of the Board of Atlas Energy s general partner and Vice Chairman of the Board of our general partner, and Edward Cohen, who serves as Chief Executive Officer and President of Atlas Energy and Chairman of the Board and Chief Executive Officer of our general partner, entered into a non-competition and non-solicitation agreement with Chevron. 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 Old Atlas. The foregoing 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 acquired by Atlas Energy from Old Atlas in February 2011) and Atlas Pipeline Partners, L.P. The non-competition agreements also prohibit Edward Cohen and Jonathan Cohen, until February 17, 2013, from soliciting for employment, or hiring, any person who was employed by Old Atlas before its merger with Chevron merger and became an employee of Old Atlas or Chevron after the merger, subject to certain limited exceptions. We will be bound by the restrictions of the non-compete agreements for so long as these individuals remain associated with us, our general partner or Atlas Energy and consequently, among other restrictions, will remain prohibited from engaging in the business of natural gas and oil production and development in certain specified counties of Pennsylvania, West Virginia and New York (other than with respect to certain wells operated or planned by the business acquired by Atlas Energy from Old Atlas in February 2011 at the time of such acquisition), including counties in which portions of the Marcellus Shale are located.

Separation and Distribution Agreement

Prior to the separation and distribution, our assets and businesses were held by Atlas Energy or one or more of its subsidiaries. In connection with the separation and distribution, we entered into an agreement with Atlas Energy, pursuant to which Atlas Energy agreed to transfer to us certain assets and liabilities comprising our businesses and to distribute approximately 5.24 million of our common units, representing an approximately 19.6% limited partner interest in us, to the Atlas Energy unitholders in a pro rata distribution.

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Transfer of Assets and Assumption of Liabilities

The separation and distribution agreement identified assets to be transferred, liabilities to be assumed and contracts to be assigned to us as part of our separation from Atlas Energy and described when and how these transfers, assumptions and assignments will occur. In particular, the separation and distribution agreement generally provided that Atlas Energy will transfer to us or one of our subsidiaries substantially all of the natural gas and oil assets and the partnership management business that Atlas Energy acquired from Old Atlas on February 17, 2011, including:

- its proved reserves located in the Appalachian Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan and the Chattanooga Shale of northeastern Tennessee;
- its producing natural gas and oil assets properties (other than its rights of way in Ohio, ownership of which will not be transferred to us, but which we will have the right to use for development and production purposes), which assets and properties we will operate for development and production purposes; and
- its partnership management business that sponsors tax-advantaged direct investment natural gas and oil partnerships, through which it funds a portion of its natural gas and oil well drilling.

We also assumed and are responsible for all liabilities and obligations related to these assets and businesses. Atlas Energy retained the following assets, which were not transferred to us in the separation:

- approximately 20.96 million of our common units, representing an approximately 78.4% limited partner interest;
- the equity of our general partner, which will hold 534,694 class A units representing a 2% general partner interest in us and all of our incentive distribution rights;
- the equity in the general partner of Atlas Energy;
- the equity in the general partner of Atlas Pipeline Partners, L.P. (NYSE: APL) and the equity in Atlas Pipeline Partners, L.P.;
- the direct and indirect ownership interest in Lightfoot Capital Partners, LP and Lightfoot Capital Partners GP, LLC; and
- its rights of way in Ohio, provided that we will have the right to use such rights of way for development and production purposes.

The separation and distribution agreement also provided that Atlas Energy will have 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.

In general, neither we nor Atlas Energy madeany representations or warranties regarding the assets, businesses or liabilities transferred or assumed, any consents or approvals that may be required in connection with such transfers or assumptions, the value or freedom from any lien or other security interest of any assets transferred, the absence of any defenses relating to any claim of either us or Atlas Energy, or the legal sufficiency of any conveyance documents. Except as expressly set forth in the contribution and assumption agreement or in any ancillary agreement, all assets were transferred on an as is, where is basis.

Indemnification

We indemnified Atlas Energy and its affiliates (other than us and our subsidiaries) and their directors, officers and employees against liabilities relating to, arising out of or resulting from:

- liabilities that we have assumed in connection with the separation arising after the separation date, including any liabilities that may result from the consummation of the separation, distribution and the related transactions; and

- our failure to make payment in respect of obligations that we have assumed pursuant to the separation and distribution agreement.

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Atlas Energy indemnified us and our subsidiaries, directors, officers and employees against liabilities relating to, arising out of or resulting from:

liabilities related to the assets that Atlas Energy specifically retained in the separation; and

Atlas Energy s failure to make payment in respect of certain obligations that it has retained pursuant to the separation and distribution agreement.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership securities proposed to be sold by our general partner, Atlas Energy or any of their respective affiliates if an exemption from the registration requirements is not otherwise available. There is no limit on the number of times that we may be required to file registration statements pursuant to this obligation. We have also agreed to include any securities held by our general partner, Atlas Energy or any of their respective affiliates in any registration statement that we file to offer securities for cash, other than an offering relating solely to an employee benefit plan. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions. In connection with any registration of this kind, we will indemnify the unitholders participating in the registration and their officers, directors and controlling persons from and against specified liabilities, including under the Securities Act or any applicable state securities laws.

Indemnification of Directors and Officers

Under our partnership agreement, in most circumstances, we will indemnify any manager, managing member, officer, director, employee, agent or trustee of our general partner or any of its affiliates and any person who is or was serving at the request of our general partner or any of its affiliates as a manager, managing member, officer, director, employee, agent, fiduciary or trustee of another person, to the fullest extent permitted by law, from and against all losses, claims or damages arising out of or incurred in connection with our business.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2011 and 2010, the accounting fees and services (in thousands) charged by Grant Thornton, LLP, our independent auditors, were as follows:

	Years Ended December 31, 2011	Years Ended December 31, 2010
Audit fees[1]	$ 350	$
Audit-related fees		
Tax fees		
Total accounting fees and services	$ 350	$

(1) Represents the aggregate fees recognized for professional services rendered by Grant Thornton LLP principally for the audit of our annual financial statements and the audit and review of our financial information included in our filings with the SEC on Form 10.

Audit Committee Pre-Approval Policies and Procedures

The audit committee of our general partner, on at least an annual basis, will review audit and non-audit services performed by Grant Thornton LLP as well as the fees charged by Grant Thornton LLP for such services. Our policy is that all audit and non-audit services must be pre-approved by the audit committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

(1) Financial Statements

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The financial statements required by this Item 15(a)(1) are set forth in Item 8.

(2) Financial Statement Schedules

None

(3) Exhibits:

Exhibit No.	Description
2.1	Separation and Distribution Agreement, dated February 23, 2012, by and among Atlas Energy, L.P., Atlas Energy GP, LLC, Atlas Resource Partners, L.P. and Atlas Resource Partners GP, LLC. The schedules to the Separation and Distribution Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.(1)
3.1	Certificate of Limited Partnership of Atlas Resource Partners, L.P. (2)
3.2	Amended and Restated Limited Partnership Agreement of Atlas Resource Partners, L.P. (4)
3.3	Certificate of Formation of Atlas Resource Partners GP, LLC. (2)
3.4	Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC.
10.1	Pennsylvania Operating Services Agreement dated as of February 17, 2011 between Chevron North America Exploration and Production (f/k/a Atlas Energy, Inc.), Atlas Energy, L.P. (f/k/a Atlas Pipeline Holdings, L.P.) and Atlas Resources, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.2	Petro-Technical Services Agreement, dated as of February 17, 2011 between Chevron North America Exploration and Production (f/k/a Atlas Energy, Inc.) and Atlas Energy, L.P. (f/k/a Atlas Pipeline Holdings, L.P.). Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.3	Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.4	Amendment No. 1 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of January 6, 2011. (5)
10.5	Amendment No. 2 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of February 2, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.6	Transaction Confirmation, Supply Contract No. 0001, under Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated February 17, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.7	Gas Gathering Agreement for Natural Gas on the Legacy Appalachian System dated as of

	June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.8	Gas Gathering Agreement for Natural Gas on the Expansion Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.9	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010.(6)
10.10	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010.(6)
10.11	Credit Agreement between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders(3)
10.12	Secured Hedge Facility Agreement among Atlas Resources, LLC, the participating partnerships from time to time party thereto, the hedge providers from time to time party thereto and Wells Fargo Bank, N.A., as collateral agent for the Hedge Providers(3)
10.13	2012 Long-Term Incentive Plan of Atlas Resource Partners, L.P. (4)
10.14	Form of Phantom Unit Grant Agreement under 2012 Long-Term Incentive Plan
10.15	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan
10.16	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan
10.17	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011(5)
10.18	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011(5)
10.19	Employment Agreement between Atlas Energy, L.P. and Matthew A. Jones dated as of November 4, 2011(7)
21.1	Subsidiaries of Atlas Resource Partners, L.P.
23.1	Consent of Grant Thornton LLP for Atlas Resource Partners, L.P.
23.2	Consent of Grant Thornton LLP for Atlas Energy E&P Operations
23.3	Consent of Wright & Company, Inc.
31.1	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2	Rule 13(a)-14(a)/15(d)-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification
99.1	Information Statement of Atlas Resource Partners, L.P., preliminary and subject to completion, dated December 1, 2011(8)
99.2	Summary Reserve Report of Wright & Company, Inc. (2)
101.INS	XBRL Instance Document(9)
101.SCH	XBRL Schema Document(9)

101.CAL	XBRL Calculation Linkbase Document(9)
101.LAB	XBRL Label Linkbase Document(9)
101.PRE	XBRL Presentation Linkbase Document(9)
101.DEF	XBRL Definition Linkbase Document(9)

(1) Previously filed as an exhibit to our Current Report on Form 8-K filed on February 24, 2012.
(2) Previously filed as an exhibit to our Registration Statement on Form 10, as amended (File No. 1-35317).
(3) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 7, 2012.
(4) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 14, 2012.
(5) Previously filed as an exhibit to Atlas Energy s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.
(6) Previously filed as an exhibit to Atlas Energy s Current Report on Form 8-K filed on November 12, 2010.
(7) Previously filed as an exhibit to Atlas Energy s Annual Report on Form 10-K for the year ended December 31, 2011.
(8) Previously filed as an exhibit to our Current Report on Form 8-K filed on February 16, 2012.
(9) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATLAS RESOURCE PARTNERS, L.P.
By: Atlas Resource Partners GP, LLC, its general partner

Date: March 29, 2012

By: /s/ EDWARD E. COHEN
Edward E. Cohen

Chairman of the Board and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated as of March 29, 2012.

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

Bruce Wolf

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