Atlas Energy, L.P.

February 15, 2012

Dear Atlas Energy, L.P. Unitholder:

We are pleased to inform you that the board of directors of the general partner of Atlas Energy, L.P. has approved the distribution of approximately 5.24 million common units representing an approximately 19.6% limited partner interest in Atlas Resource Partners, L.P., a Delaware limited partnership formed by Atlas Energy to hold substantially all of its current natural gas and oil development and production assets and its partnership management business. The distribution will be made by Atlas Energy on a pro rata basis to its unitholders, and, as a result of the distribution, Atlas Resource Partners will become a separate, publicly traded company.

The distribution of Atlas Resource Partners common units will occur on March 13, 2012, by way of a pro rata distribution to Atlas Energy unitholders. Each Atlas Energy unitholder will receive 0.1021 of a common unit of Atlas Resource Partners for each Atlas Energy common unit held by such unitholder at the close of business on February 28, 2012, the record date of the distribution. Atlas Energy will not distribute any fractional common units of Atlas Resource Partners, but instead will distribute cash in lieu of any fractional common unit of Atlas Resource Partners that you would have received after application of the above ratio.

Immediately following the distribution, Atlas Energy will continue to own approximately 20.96 million common units of Atlas Resource Partners, representing an approximately 78.4% limited partner interest in the partnership. In addition, Atlas Energy will own 100% of the equity of the general partner of Atlas Resource Partners, Atlas Resource Partners GP, LLC. The general partner of Atlas Resource Partners will own class A units representing a 2% general partner interest in the partnership and incentive distribution rights in the partnership, as more fully described in the accompanying information statement.

The distribution will be issued in book-entry form only, which means that no physical stock certificates will be issued. If you own your Atlas Energy units through a broker, your brokerage account will be credited with the new common units of Atlas Resource Partners. If you have an account with Atlas Energy's transfer agent (American Stock Transfer & Trust Company), the new common units of Atlas Resource Partners will be credited to your account at American Stock Transfer. Unitholder approval of the distribution is not required, and you are not required to take any action to receive your common units of Atlas Resource Partners. Following the distribution, if you are an Atlas Energy unitholder on the record date, you will own both common units of Atlas Energy and common units of Atlas Resource Partners.

In general, the distribution of common units of Atlas Resource Partners by Atlas Energy should not be taxable for U.S. federal income tax purposes, except to the extent that the aggregate amount of money you receive (including cash received in lieu of fractional units) or are deemed to receive as a result of the distribution exceeds the tax basis in your interest in Atlas Energy common units immediately before the distribution. The rules governing the tax consequences of the distribution are complex. You are urged to read the summary of the U.S. federal income tax consequences of the distribution later in this information statement and to consult your own tax advisor regarding the tax consequences of the distribution to you in your particular circumstances.

Atlas Resource Partners has been authorized to have its common units listed on the New York Stock Exchange under the symbol "ARP." Atlas Energy common units will continue to trade on the New York Stock Exchange under the symbol "ATLS."

The enclosed information statement, which is being mailed to all Atlas Energy common unitholders as of the record date, describes the distribution of common units of Atlas Resource Partners in detail and contains important information about Atlas Resource Partners. We urge you to read this information statement carefully.

We want to thank you for your continued support of Atlas Energy, and we look forward to your support of Atlas Resource Partners in the future.

Edward E. Cohen

Edward E. Cohen
Chief Executive Officer
Atlas Energy GP, LLC

Jonathan Z. Cohen
Chairman of the Board of Directors
Atlas Energy GP, LLC

INFORMATION STATEMENT

ATLAS RESOURCE PARTNERS, L.P.

This information statement is being furnished in connection with the distribution by Atlas Energy, L.P. to its unitholders of approximately 5.24 million common units representing an approximately 19.6% limited partner interest in Atlas Resource Partners, L.P., which was formed by Atlas Energy to hold substantially all of its current natural gas and oil development and production assets and its partnership management business. The distribution will be made by Atlas Energy on a pro rata basis to its unitholders, and, as a result of the distribution, Atlas Resource Partners will become a separate, publicly traded company.

For every common unit of Atlas Energy held of record by you as of the close of business on February 28, 2012, the record date for the distribution, you will receive 0.1021 of a common unit of Atlas Resource Partners. You will receive cash in lieu of any fractional common unit of Atlas Resource Partners that you would have received after application of the above ratio. We expect the distribution to occur on March 13, 2012, which we refer to as the "distribution date."

In general, the distribution of common units of Atlas Resource Partners by Atlas Energy should not be taxable for U.S. federal income tax purposes, except to the extent that the aggregate amount of money you receive (including cash received in lieu of fractional units) or are deemed to receive as a result of the distribution exceeds the tax basis in your interest in Atlas Energy common units immediately before the distribution. The rules governing the tax consequences of the distribution are complex. You are urged to read the summary of the U.S. federal income tax consequences of the distribution later in this information statement and to consult your own tax advisor regarding the tax consequences of the distribution to you in your particular circumstances.

As discussed under "The Separation and Distribution—Trading Between the Record Date and Distribution Date" on page 65, if you sell your Atlas Energy common units in the "regular-way" market after the record date and before the distribution date, you also will be selling your right to receive Atlas Resource Partners common units in connection with the distribution.

No vote of Atlas Energy unitholders is required in connection with the distribution. Therefore, you are not required to send us a proxy, and you are requested not to send us a proxy, in connection with the distribution. You do not need to pay any consideration, exchange or surrender your existing common units of Atlas Energy or take any other action to receive your Atlas Resource Partners common units.

All of the outstanding Atlas Resource Partners common units are currently owned by Atlas Energy. Accordingly, there currently is no public trading market for such common units, although we expect that a limited market, commonly known as a "when-issued" trading market, will develop on or shortly before the record date for the distribution, and we expect "regular-way" trading of Atlas Resource Partners common units to begin on the first trading day following the distribution date. Atlas Resource Partners has been authorized to have its common units listed on the New York Stock Exchange under the ticker symbol "ARP."

In reviewing this information statement, you should carefully consider the matters described in the section entitled "Risk Factors" beginning on page 28 of this information statement.

Neither the U.S. Securities and Exchange Commission nor any state securities commission has approved or disapproved of any of the securities of Atlas Resource Partners, L.P. or determined whether this information statement is truthful or complete. Any representation to the contrary is a criminal offense.

This information statement does not constitute an offer to sell or the solicitation of an offer to buy any securities.

The date of this information statement is February 15, 2012.

This information statement was first mailed to Atlas Energy unitholders on or about February 17, 2012.

TABLE OF CONTENTS

NOTE REGARDING THE USE OF CERTAIN TERMS

Except as otherwise indicated or unless the context otherwise requires, the information included in this information statement, including the combined financial statements of Atlas Resource Partners, L.P., which are comprised of substantially all of the assets and liabilities associated with Atlas Energy, L.P.'s current natural gas and oil development and production assets and its partnership management business, assumes the completion of all the transactions referred to in this information statement in connection with the separation and distribution. Unless the context otherwise requires, references in this information statement to "Atlas Resource Partners, L.P.," "Atlas Resource Partners," "the partnership," "we," "us," "our" and "our company" refer to Atlas Resource Partners, L.P., a Delaware limited partnership, and its combined subsidiaries and whose common units will be distributed in the distribution.

References in this information statement to "Atlas Energy" or "Atlas Energy, L.P." refer to Atlas Energy, L.P., a Delaware limited partnership.

References in this information statement to "our general partner" refer to Atlas Resource Partners GP, LLC, a Delaware limited liability company, the general partner of Atlas Resource Partners and a wholly owned subsidiary of Atlas Energy.

INDUSTRY AND MARKET DATA

In this information statement, we rely on and refer to information and statistics regarding the natural gas and oil production and development industries. We obtained this data from independent publications or other publicly available information that we believe to be reliable.

QUESTIONS AND ANSWERS ABOUT THE DISTRIBUTION

What is Atlas Resource Partners and why is Atlas Energy separating Atlas Resource Partners' business and distributing its common units?	Atlas Energy currently owns all of the limited partner interests of Atlas Resource Partners, which represent a 98% limited partner interest in the partnership. Atlas Energy also owns all of the equity of Atlas Resource Partners GP LLC, the general partner of Atlas Resource Partners. The general partner, in turn, owns all of the class A units of Atlas Resource Partners, which represent a 2% general partner interest in the partnership, and all of the incentive distribution rights in Atlas Resource Partners. The board of directors of the general partner of Atlas Energy has approved the distribution to the Atlas Energy unitholders of approximately 5.24 million common units representing an approximately 19.6% limited partner interest in Atlas Resource Partners. We refer to this distribution of common units as the "distribution." Prior to the distribution, Atlas Energy will contribute to Atlas Resource Partners substantially all of the assets and liabilities associated with its current natural gas and oil development and production assets and its partnership management business. The separation of Atlas Resource Partners from Atlas Energy in this manner and the distribution of the common units of Atlas Resource Partners is intended to provide you with equity investments in two separate public companies that will create long-term value for the current Atlas Energy unitholders.
Why am I receiving this document?	Atlas Energy is delivering this document to you because you are a holder of common units of Atlas Energy. If you are a holder of common units of Atlas Energy on February 28, 2012, the record date for the distribution, you are entitled to receive 0.1021 of a common unit of Atlas Resource Partners for each common unit of Atlas Energy that you held at the close of business on the record date. No fraction of an Atlas Resource Partners common unit will be issued in the distribution. Instead, you will receive cash in lieu of any fractional common unit of Atlas Resource Partners that you would have received after application of the above ratio. This document will help you understand how the separation and distribution will affect your investment in Atlas Energy and your investment in Atlas Resource Partners after the separation and distribution.
How will the separation of Atlas Resource Partners work?	The separation will be accomplished through a transaction in which substantially all of the natural gas and oil development and production assets and the partnership management business of Atlas Energy will be transferred to Atlas Resource Partners. After such transfer, which we refer to as the "separation," Atlas Energy will distribute to its unitholders, on a pro rata basis, approximately 5.24 million common units representing an approximately 19.6% limited partner interest in Atlas Resource Partners.
What is the record date for the distribution?	The record date for the distribution will be February 28, 2012.
When will the distribution occur?	We expect that the distribution will occur on March 13, 2012. The distribution will be made to holders of record of Atlas Energy common units at the close of business on the record date.

What do unitholders need to do to participate in the distribution?

Holders of Atlas Energy common units as of the record date will not be required to take any action to receive Atlas Resource Partners common units in the distribution, but you are urged to read this entire information statement carefully. No unitholder approval of the distribution is required or sought. You are not being asked for a proxy, and you are requested not to send us a proxy. You will not be required to make any payment, surrender or exchange of your Atlas Energy common units or to take any other action to receive your Atlas Resource Partners common units.

Will I receive physical certificates representing common units of Atlas Resource Partners following the distribution?

No. Following the separation and distribution, Atlas Resource Partners will not issue physical certificates representing common units of Atlas Resource Partners. If you own Atlas Energy common units as of the close of business on the record date, Atlas Energy, with the assistance of American Stock Transfer & Trust Company, LLC, or AST, the distribution agent, will electronically issue Atlas Resource Partners common units to you or to your brokerage firm on your behalf by way of direct registration in book-entry form. Atlas Resource Partners will not issue paper certificates. If you are a registered unitholder of Atlas Energy (meaning you own your units directly through an account with Atlas Energy's transfer agent, AST), AST will mail you a book-entry account statement that reflects the number of Atlas Resource Partners common units you own. If you own your Atlas Energy common units through a bank or brokerage account, your bank or brokerage firm will credit your account with the Atlas Resource Partners common units.

Following the distribution, unitholders whose common units are held at the transfer agent may request that either their common units of Atlas Energy or Atlas Resource Partners be transferred to a brokerage or other account at any time. You should consult your broker if you wish to transfer your units.

How many common units of Atlas Resource Partners will I receive in the distribution?

Atlas Energy will distribute to you 0.1021 of a common unit of Atlas Resource Partners for each common unit of Atlas Energy held at the close of business on the record date. Based on approximately 51.3 million common units of Atlas Energy that are expected to be outstanding as of the record date, a total of approximately 5.24 million common units of Atlas Resource Partners will be distributed. For additional information on the distribution, see "The Separation and Distribution" beginning on page 61.

Will Atlas Resource Partners issue fractional units in the distribution?

No. Atlas Resource Partners will not issue fractional common units in the distribution. Fractional units that Atlas Energy unitholders otherwise would have been entitled to receive will instead be aggregated and sold in the public market by the distribution agent. The aggregate net cash proceeds of these sales will be distributed ratably to those unitholders who would otherwise have been entitled to receive fractional units.

What are the conditions to the distribution?

The distribution is subject to a number of conditions, including, among others, that no stop order being is in effect for the registration statement of which this information statement forms a part and that no order or injunction is in effect preventing consummation of the separation or distribution.

We cannot assure you that any or all of these conditions will be met. For a complete discussion of all of the conditions to the distribution, see "The Separation and Distribution—Conditions to the Distribution" beginning on page 65.

Can Atlas Energy decide to cancel the distribution even if all the conditions have been met?

Yes. The distribution is subject to the satisfaction or waiver of certain conditions. For more information, see the section entitled "The Separation and Distribution—Conditions to the Distribution" beginning on page 65. Until the distribution has occurred, Atlas Energy has the right to terminate the distribution, even if all of the conditions are satisfied, if at any time the board of directors of Atlas Energy L.P.'s general partner determines that the distribution is not in the best interests of Atlas Energy and its unitholders.

What if I want to sell my common units of Atlas Energy or Atlas Resource Partners?

You should consult with your financial advisors, such as your stockbroker, bank or tax advisor. Neither Atlas Energy nor Atlas Resource Partners makes any recommendations on the purchase, retention or sale of common units of Atlas Energy or Atlas Resource Partners.

If you decide to sell any units after the record date, but before the distribution, you should make sure your stockbroker, bank or other nominee understands whether you want to sell your Atlas Energy common units or the Atlas Resource Partners common units that you will receive in the distribution or both. If you sell your Atlas Energy common units prior to the record date or sell your entitlement to receive common units of Atlas Resource Partners in the distribution on or prior to the distribution date, you will not be entitled to receive any Atlas Resource Partners common units in the distribution.

What is "regular-way" and "ex-distribution" trading?

Beginning on or shortly before the record date and continuing up to and through the distribution date, it is expected that there will be two markets in Atlas Energy L.P. common units: a "regular-way" market and an "ex-distribution" market. Common units of Atlas Energy that trade in the "regular-way" market will trade with an entitlement to common units of Atlas Resource Partners distributed pursuant to the distribution. Common units of Atlas Energy that trade in the "ex-distribution" market will trade without an entitlement to common units of Atlas Resource Partners distributed pursuant to the distribution.

If you decide to sell any common units of Atlas Energy before the distribution date, you should make sure your stockbroker, bank or other nominee understands whether you want to sell your common units of Atlas Energy with or without your entitlement to Atlas Resource Partners common units pursuant to the distribution.

Where will I be able to trade common units of Atlas Resource Partners?

There is not currently a public market for the common units of Atlas Resource Partners. Atlas Resource Partners has been approved to list its common units on the New York Stock Exchange, or the NYSE, under the symbol "ARP." If it receives authorization for the listing, we anticipate that trading in common units of Atlas Resource Partners will begin on a "when-issued" basis on or shortly before the record date and will continue up to and through the distribution date and that "regular-way" trading in such common units will begin on the first trading day following the distribution date. If trading begins on a "when-issued" basis, you may purchase or sell common units of Atlas Resource Partners up to and through the distribution date, but your transaction will not settle until after the distribution date. We cannot predict the trading prices for our common units before, on or after the distribution date. For more information regarding "regular-way" trading and "when-issued" trading, see the section entitled "The Separation and Distribution—Trading Between the Record Date and Distribution Date" on page 65.

Will the number of common units of Atlas Energy that I own change as a result of the distribution?

No. The number of common units of Atlas Energy that you own will not change as a result of the distribution.

What will happen to the listing of Atlas Energy common units?

It is expected that, after the distribution, Atlas Energy common units will continue to be traded on the NYSE under the symbol "ATLS."

Will the distribution affect the market price of my Atlas Energy common units?

As a result of the distribution, the trading price of Atlas Energy common units immediately following the distribution may be lower than the "regular-way" trading price of such units immediately prior to the distribution because the trading price of Atlas Energy will no longer reflect the value of 100% ownership of the current natural gas and oil development and production assets and the partnership management business held by Atlas Resource Partners.

Atlas Energy believes that over time following the distribution, assuming the same market conditions and the realization of the expected benefits of the separation, the sum of the value of the Atlas Energy common units and the value of the Atlas Resource Partners common units should be greater than the value of Atlas Energy common units if the separation and distribution did not occur. There can be no assurance, however, that such a higher aggregate value will be achieved. This means, for example, that the combined trading prices of one Atlas Energy common unit and 0.1021 of a common unit of Atlas Resource Partners after the distribution may be equal to, greater than or less than the trading price of one Atlas Energy common unit before the distribution.

What are the material U.S. federal income tax consequences of the distribution of our common units by Atlas Energy?

In general, the distribution of common units of Atlas Resource Partners by Atlas Energy to a U.S. holder (as defined in the section entitled "Certain U.S. Federal Income Tax Matters" beginning on page 220) of common units of Atlas Energy should not be taxable to the U.S. holder for U.S. federal income tax purposes, except to the extent that the aggregate amount of money you receive (including cash received in lieu of fractional units) or are deemed to receive as a result of the distribution exceeds the tax basis in such holder's interest in Atlas Energy common units immediately before the distribution.

The rules governing the tax consequences of the distribution are complex. You are urged to read the summary of the U.S. federal income tax consequences of the distribution in the section entitled "Certain U.S. Federal Income Tax Matters" beginning on page 220 and to consult your own tax advisor regarding the tax consequences of the distribution to you in your particular circumstances.

How will I determine the initial basis that I will have in the Atlas Resource Partners common units I receive in the distribution?

A U.S. holder's initial basis in the common units of Atlas Resource Partners received by such U.S. holder in the distribution generally will be equal to Atlas Energy's adjusted basis in such common units immediately before the distribution for U.S. federal income tax purposes. However, such U.S. holder's initial basis in such common units shall not exceed the adjusted basis of such U.S. holder's interest in Atlas Energy, reduced by any money distributed in the same transaction. Atlas Energy expects to provide unitholders with information regarding its adjusted basis for U.S. federal income tax purposes of our common units distributed in the distribution.

The rules governing the determination of a unitholder's initial basis of our common units distributed in the distribution and the other tax consequences of the distribution are complex. You are urged to read the summary of the U.S. federal income tax consequences of the distribution in the section entitled "Certain U.S. Federal Income Tax Matters" beginning on page 220 and to consult your own tax advisor regarding the determination of your initial basis in our common units distributed to you in the distribution and the other tax consequences of the distribution to you in your particular circumstances.

Does Atlas Resource Partners plan to pay distributions?

Atlas Resource Partners will distribute to its partners all of its "available cash" for that quarter, which generally means all cash on hand of the partnership at the end of the quarter less reserves that its general partner determines are appropriate to provide for the partnership's operating costs, including potential acquisitions, and to provide funds for distributions to the holders of its partnership interests for any one or more of the next four quarters.

Cash distributions will be characterized as distributions from either operating surplus or capital surplus. This distinction affects the amounts distributed to unitholders relative to its general partner.

Atlas Resource Partners will distribute available cash from operating surplus for any quarter in the following manner:

- first, 2% to the holders of the class A units (which will be held by the general partner of Atlas Resource Partners) and 98% to the holders of the common units, each pro rata, until each holder has received $0.40 per outstanding unit, which we refer to as the "minimum distribution";
- second, 2% to the holders of the class A units and 98% to the holders of the common units, each pro rata, until each holder has received $0.46 per outstanding unit, which we refer to as the "first target distribution";
- third, 2% to the holders of the class A units and 85% to the holders of the common units, each pro rata, and 13% to the holder of the incentive distribution rights (which will initially be the general partner of Atlas Resource Partners), until each holder of the class A units and the holders of the common units have received $0.50 per outstanding unit, which we refer to as the "second target distribution";

- fourth, 2% to the holders of the class A units and 75% to the holders of the common units, each pro rata, and 23% to the holder of the incentive distribution rights, until each holder of the class A units and holders of the common units have received $0.60 per outstanding unit, which we refer to as the "third target distribution";
- after that, 2% to the holders of the class A units and 50% to the holders of the common units, each pro rata, and 48% to the holder of the incentive distribution rights.

Atlas Resource Partners will distribute available cash from capital surplus for any quarter in the following manner:

- first, 2% to the holders of the class A units and 98% to the holders of the common units, each pro rata, until the minimum quarterly distribution is reduced to zero; and
- after that, Atlas Resource Partners will distribute all available cash from capital surplus as if it were from operating surplus.

The class A units represent a 2% general partner interest in Atlas Resource Partners, and the holder of such units will be entitled to 2% of the partnership's cash distributions without any obligation to make future capital contributions to the partnership. The 2% sharing ratio of the class A units will not be reduced if Atlas Resource Partners issues additional common units in the future. Because the 2% sharing ratio will not be reduced if Atlas Resource Partners issues additional common units, and in order to ensure that each class A unit represents the same percentage economic interest in Atlas Resource Partners as one common unit, if Atlas Resource Partners issues additional common units, it will also issue to its 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.

All decisions regarding the payment of distributions by Atlas Resource Partners will be made by its general partner from time to time in accordance with our partnership agreement. There is no guarantee of distributions at a particular level or of any distributions being made.

Atlas Resource Partners believes, based on the assumptions and considerations discussed in the section entitled "Cash Distribution Policy—Estimated Cash Available for Distribution" beginning on page 84, that it will have sufficient cash available for distribution to enable it to pay the minimum distribution of $0.40 on all of the common units and class A units for each quarter for the twelve months ending December 31, 2012. If it had completed the separation and distribution on January 1, 2010, the amount of pro forma available cash generated during the twelve months ended December 31, 2010 would have been sufficient to pay the minimum distribution on all of its common units and class A units. If it had completed the separation and distribution on October 1, 2010, the amount of pro forma available cash generated during the twelve months ended September 30, 2011 would have been insufficient by approximately $0.5 million to pay the minimum

	distribution on all of its common units and class A units. For a calculation of its ability to make distributions to you based on its pro forma results for the twelve months ended December 31, 2010 and September 30, 2011, see "Cash Distribution Policy—Estimated Cash Available for Distribution" beginning on page 84.
What will the relationship be between Atlas Energy and Atlas Resource Partners following the separation?	Before the distribution, Atlas Resource Partners will enter into a separation and distribution agreement with Atlas Energy to effect the separation and distribution and provide a framework for its relationships with Atlas Energy after the separation. This agreement will provide for the allocation between Atlas Energy and Atlas Resource Partners of Atlas Energy's assets, liabilities and obligations and will govern certain relationships between Atlas Energy and Atlas Resource Partners subsequent to the separation and distribution. Atlas Resource Partners will also enter into an amended and restated partnership agreement with Atlas Energy and its general partner, which is a wholly owned subsidiary of Atlas Energy. The partnership agreement will also govern certain relationships between Atlas Energy, Atlas Resource Partners, Atlas Resource Partners' limited partners, and its general partner after the separation and distribution. We cannot assure you that these agreements will be on terms as favorable to Atlas Resource Partners as agreements with unaffiliated third parties. In addition, immediately following the distribution, Atlas Energy will retain approximately 20.96 million common units representing an approximately 78.4% limited partner interest in Atlas Resource Partners. In addition, Atlas Energy will own 100% of the equity of Atlas Resource Partners GP, LLC, the general partner of Atlas Resource Partners. This general partner will own all of the class A units representing a 2% general partner interest, as well as all of the incentive distribution rights, in Atlas Resource Partners. As a result of this ownership, Atlas Energy will control the operations of Atlas Resource Partners. As the owner of the general partner, Atlas Energy also will have the ability to select all of the members of the board of directors of the general partner. For more information, see the section entitled "Certain Relationships and Related Transactions" beginning on page 191.
Are there risks to owning Atlas Resource Partners common units?	Yes. Atlas Resource Partners' business is subject to both general and specific risks relating to its business, the separation (including its relationship with Atlas Energy) and its being a separate publicly traded company. These risks are described in the section entitled "Risk Factors" beginning on page 28. We encourage you to read that section carefully.
Who will be the distribution agent, transfer agent, and registrar for the Atlas Resource Partners common units?	The distribution agent, transfer agent, and registrar for the Atlas Energy common units will be American Stock Transfer & Trust Company, LLC. For questions relating to the transfer or mechanics of the distribution, you should contact: American Stock Transfer & Trust Company Attention: Atlas Energy, L.P. Representative 59 Maiden Lane New York, New York 10038 (800) 937-5449

If your units are held by a bank, broker or other nominee, you may call the information agent for the distribution, American Stock Transfer & Trust Company, toll free at (800) 937-5449.

Where can I get more information about Atlas Energy and Atlas Resource Partners?

Before the separation, if you have any questions relating to the separation, you should contact:

Atlas Energy, L.P.
Investor Relations
Park Place Corporate Center One
1000 Commerce Drive, 4th Floor
Pittsburgh, Pennsylvania 15275
(877) 280-2857

After the separation, if you have any questions relating to Atlas Resource Partners common units or the distribution of our common units, you should contact:

Atlas Resource Partners, L.P.
Investor Relations
Park Place Corporate Center One
1000 Commerce Drive, 4th Floor
Pittsburgh, Pennsylvania 15275
(877) 280-2857

INFORMATION STATEMENT SUMMARY

This summary highlights selected information from this information statement relating to Atlas Resource Partners, Atlas Resource Partners' separation from Atlas Energy and the distribution of Atlas Resource Partners common units by Atlas Energy to its unitholders. For a more complete understanding of our businesses and the separation and distribution, you should read this information statement carefully.

Except as otherwise indicated or unless the context otherwise requires, the information included in this information statement, including the financial statements of Atlas Resource Partners, assumes the completion of all the transactions referred to in this information statement in connection with the separation and distribution.

Our Business

Overview

We are a limited partnership and 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 coinvest, to finance a portion of our natural gas and oil development and production activities. Our present 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.

We were formed in October 2011 to own and operate substantially all of the current natural gas and oil development and production assets and the partnership management business of Atlas Energy. 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 upon completion of the separation and distribution.

As of September 30, 2011, our principal assets consisted of:

- working interests in approximately 9,500 gross producing natural gas and oil wells;
- overriding royalty interests in approximately 630 gross producing natural gas and oil wells;
- net daily production of 36.2 Mmcfed for the nine months ended September 30, 2011;
- proved reserves of 187.1 Bcfe at December 31, 2010; 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.

The following table shows our financial and operating data for the periods indicated. The following table includes the non-GAAP financial measure of segment margin. For a definition of this measure and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with U.S. generally accepted accounting principles, or "GAAP," see the notes to the table:

	Nine Months Ended September 30,		Years Ended December 31,				
	2011	2010	2010	2009	2008	2007	2006
Segment margin (in thousands)[1]:							
Natural gas and oil production margin	$ 39,701	$ 53,953	$ 69,727	$ 87,422	$101,979	$ 81,377	$ 74,568
Partnership management margin	21,300	37,247	45,309	74,152	82,563	67,487	22,808
Total segment margin	**$ 61,001**	**$ 91,200**	**$115,036**	**$161,574**	**$184,542**	**$148,864**	**$ 97,376**
Operating data[2]:							
Partnership investor funds raised	$ 32,459	$149,342	$149,342	$353,444	$438,400	$363,283	$218,513
Wells drilled:							
Gross	62	82	117	267	823	1,118	719
Net to our interest[3]	14	22	34	68	274	388	227
Net production[4]:							
Natural gas (Mcfd)	31,687	36,610	35,855	38,644	32,791	27,156	24,511
Oil (bpd)	296	391	373	427	423	418	413
Natural gas liquids (bpd)	449	493	499	101	—	—	—
Total (mcfed)	**36,158**	**41,914**	**41,090**	**41,814**	**35,327**	**29,664**	**26,989**
Average realized sales price:							
Natural gas (per Mcf)[5]	$ 5.24	$ 7.15	$ 7.08	$ 7.54	$ 9.40	$ 8.91	$ 8.83
Oil (per Bbl)	$ 90.65	$ 75.66	$ 77.31	$ 71.34	$ 92.28	$ 70.11	$ 62.30
Natural gas liquids (per Bbl)	$ 48.43	$ 36.67	$ 37.78	$ 36.19	$ —	$ —	$ —
Production costs (per Mcfe):							
Lease operating expenses[6]	$ 1.01	$ 1.27	$ 1.27	$ 1.10	$ 1.06	$ 0.86	$ 0.83
Net acreage[7]:							
Developed	302,022						
Undeveloped	249,524						
Proved reserves, net to us (Mmcfe)	187,056						

(1) We define segment margin as total operating revenues less total related direct operating costs, excluding direct depreciation, depletion and amortization, for each of our operating segments. Our segment margin equals the sum of our natural gas and oil production and partnership management segment's operating revenues less total related direct operating costs, excluding direct depreciation, depletion and amortization. We include a segment margin as a supplemental disclosure because it represents the aggregate results of our operating segments. As an indicator of our operating performance, segment margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our segment margin may not be comparable to a similarly titled measure of another company because other entities may not calculate segment margin in the same manner. The following reconciles segment margin to our operating income for the periods indicated (in thousands):

	Nine Months Ended September 30,		Years Ended December 31,				
	2011	2010	2010	2009	2008	2007	2006
Segment margin:							
Natural gas and oil production margin:							
Natural gas and oil production revenue	$ 51,654	$ 70,816	$ 93,050	$112,979	$127,083	$ 99,015	$ 88,449
Natural gas and oil production costs	(11,953)	(16,863)	(23,323)	(25,557)	(25,104)	(17,638)	(13,881)
Natural gas and oil production margin	39,701	53,953	69,727	87,422	101,979	81,377	74,568

	Nine Months Ended September 30,		Years Ended December 31,				
	2011	2010	2010	2009	2008	2007	2006
Partnership management margin:							
Well construction and completion revenue	64,336	176,685	206,802	372,045	415,036	321,471	198,567
Gathering and processing revenue	14,048	11,414	14,087	18,839	19,098	13,781	9,074
Administration and oversight revenue	5,073	7,473	9,716	15,554	19,277	17,955	11,762
Well services revenue	15,051	15,589	20,994	17,859	18,513	16,663	12,953
Well construction and completion costs	(54,754)	(149,724)	(175,247)	(315,546)	(359,609)	(279,540)	(172,666)
Gathering and processing costs	(16,377)	(16,499)	(20,221)	(25,269)	(19,098)	(13,781)	(29,545)
Well services costs	(6,077)	(7,691)	(10,822)	(9,330)	(10,654)	(9,062)	(7,337)
Partnership management margin	21,300	37,247	45,309	74,152	82,563	67,487	22,808
Total segment margin	61,001	91,200	115,036	161,574	184,542	148,864	97,376
Less:							
General and administrative expense	(12,275)	(8,536)	(11,381)	(15,832)	(13,074)	(9,864)	(24,124)
Depreciation, depletion & amortization	(24,019)	(31,929)	(40,758)	(43,712)	(39,781)	(28,388)	(22,491)
Asset impairment	—	—	(50,669)	(156,359)	—	—	—
Operating income	$ 24,707	$ 50,735	$ 12,228	$ (54,329)	$ 131,687	$ 110,612	$ 50,761

(2) "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.

(3) 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.

(4) 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.

(5) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010 and 2009. Including the effect of this subordination, the average realized gas sales prices were $4.44 per Mcf ($3.89 per Mcf before the effects of financial hedging) and $5.78 per Mcf ($3.47 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of our production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business—Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

(6) 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 $0.67 per Mcfe ($1.21 per Mcfe for total production costs) and $0.86 per Mcfe ($1.47 per Mcfe for total production costs for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business—Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

(7) Developed acres are acres spaced or assigned to productive wells. 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. Net acres is the sum of 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 acre.

Gas and Oil Production

Currently, our natural gas and oil production operations are focused in various shale plays in the Northeastern and Midwestern United States, both through direct interest wells and ownership interests in wells drilled through our investment partnerships. As of September 30, 2011, we have established production positions in the following areas:

- the Appalachian Basin, including in the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Chattanooga Shale in northeastern Tennessee;
- the Illinois Basin, including in the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; and
- the Denver-Julesberg Basin, including in the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

As of September 30, 2011, we owned interests in approximately 9,500 gross wells, principally in the Appalachian Basin, of which we operated over 7,800. During the three years ended December 31, 2010, we drilled over 1,200 gross wells (over 375 net to our interest). 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, and an incremental interest in each partnership for which we do not make any additional capital contribution.

Partnership Management

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 18% to 31% of the overall capitalization in a particular partnership. We also receive an additional interest, typically 5% to 10%, in each partnership 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 23% to 41%.

Over the last four years, we raised over $1.3 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.

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%.

Natural Gas 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 option 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 proposed new credit facility will 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.

Business Strategy

Our present goal is to increase the distributions to our unitholders by continuing to grow the net production from our natural gas and oil development and production business as well as the fee-based revenues from our partnership management business. The key elements of our current business strategy are:

- expand our natural gas and oil production;
- expand our fee-based revenue through our sponsorship of investment partnerships;
- expand operations through strategic acquisitions;
- continue to maintain control of operations and costs; and
- continue to manage our exposure to commodity price risk.

Competitive Strengths

We believe that 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;
- fee-based revenues from our investment partnerships provide a stable foundation for our distributions;
- we are one of the leading sponsors of tax-advantaged investment partnerships;
- we have a high quality, long-lived reserve base;
- through our general partner and its affiliates, we have significant experience in making accretive acquisitions; and
- through our general partner and its affiliates, we have significant engineering, geologic and management experience.

Risks

An investment in our common units involves risks associated with our business. The following list of risk factors is not exhaustive. Please read carefully the risks relating to these and other matters described under "Risk Factors" beginning on page 28 and "Forward-Looking Statements" beginning on page 59.

Risks Relating to Our Business

- If commodity prices decline significantly, our cash flow from operations will decline;
- 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;
- Drilling for and producing natural gas are high-risk activities with many uncertainties;
- Unless we replace the oil and natural gas reserves received from Atlas Energy in connection with the separation, our reserves and production will decline, which would reduce our cash flow from operations and income;
- Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays;
- We will be 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;
- We may not be able to continue to raise funds through our investment partnerships at desired levels, which may restrict our ability to maintain our drilling activity at recent levels; and
- Changes in tax laws may impair our ability to obtain capital funds through investment partnerships.

Risks Relating to the Separation

- We have no operating history as a separate public company, and our historical and pro forma financial information is not necessarily representative of the results that we would have achieved had we been the owner or operator of our assets and may not be a reliable indicator of our future results; and
- Estimates of the reserves we will receive from Atlas Energy in connection with the separation 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.

Risks Relating to the Ownership of Our Common Units

- If the unit price declines after the distribution, you could lose a significant part of your investment;
- Sales of our common units following the distribution may cause our unit price 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; and
- We would not have generated sufficient available cash on a pro forma basis to have paid the minimum quarterly distribution on all of our outstanding common and class A units for the twelve months ended September 30, 2011.

Tax Risks to Unitholders

- Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes;
- You may be required to pay taxes on income from us even if you do not receive any cash distributions from us;
- 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; and
- You may be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

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

- Atlas Energy will own common units representing an approximately 78.4% limited partner interest and all of the equity of our general partner, which, in turn, will own class A units representing a 2% general partner interest following the distribution. Therefore, Atlas Energy will have effective control of us;
- 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, you 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;
- Atlas Energy owns and controls our general partner, which has the authority to conduct our business and manage our operations. Atlas Energy will have conflicts of interest, which may permit it to favor its own interests to your detriment;
- Our partnership agreement eliminates our general partner’s fiduciary duties to holders of our common units;
- 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 restricts the remedies available to holders of our common units for actions taken by our general partner; and
- 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.

Separation and Distribution

We are a recently formed limited partnership that will, prior to the distribution, directly or indirectly receive and hold substantially all of the natural gas and oil production and development assets and the partnership management business currently owned by Atlas Energy. On February 17, 2011, Atlas Energy (then named Atlas Pipeline Holdings, L.P.) acquired certain producing natural gas and oil production and development assets, a partnership management business that sponsors tax-advantaged direct investment natural gas and oil partnerships, and other assets from Chevron Northeast Upstream Corporation (then named Atlas Energy, Inc.), which we refer to as "Old Atlas." In connection with the separation and distribution described in this information statement, Atlas Energy will contribute many of these assets to us. We do not currently conduct any significant operations outside of the operation of these assets.

In this information statement, we describe the business and assets that will be held by us following the separation and distribution. Our businesses are subject to various risks. For a description of these risks, see the sections entitled "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 28 and page 99, respectively.

The board of directors of Atlas Energy's general partner has approved the transfer of substantially all of Atlas Energy's natural gas and oil development and production business and its partnership management business to us, as well as the distribution to the Atlas Energy unitholders of common units representing an approximately 19.6% limited partner interest in Atlas Resource Partners. As a result of the separation and distribution, our common units will be publicly traded and separate from the Atlas Energy common units.

Immediately after the separation and distribution, Atlas Energy will continue to own approximately 20.96 million of our common units, representing an approximately 78.4% limited partner interest in us. In addition, Atlas Energy will own all of the equity of our general partner, Atlas Resource Partners GP, LLC. Our general partner, in turn, will own 534,694 class A units representing a 2% general partner interest in us, as well as all of our incentive distribution rights.

Before the separation and distribution, we will enter into a separation and distribution agreement and an amended and restated partnership agreement with Atlas Energy to effect the separation and distribution and provide a framework for the relationships among us, Atlas Energy, our limited partners and our general partner after the separation. These agreements will provide for the transfer of assets and liabilities comprising our business, as well as the obligations that will govern our relationship subsequent to the separation.

Simultaneously with or prior to the closing of the separation and distribution, we anticipate entering into a senior secured revolving credit facility, which we refer to as the credit facility, with an initial borrowing base of $138 million, and have received commitments from a group of lenders with respect to such a facility. The anticipated maturity of the credit facility is March 2016. We anticipate that the credit facility will allow us to borrow up to the lesser of the total commitments and the determined amount of the borrowing base, which will be based upon the loan collateral value assigned to our various natural gas and oil properties and other assets, and that the borrowing base under the credit facility will be re-determined semi-annually, with additional interim redeterminations permitted under certain circumstances.

At our election, interest on borrowings under the credit facility will be determined by reference to either LIBOR plus an applicable margin between 2.00% and 3.25% per annum or the "alternate base rate" plus an applicable margin between 1.00% and 2.25% per annum. These margins will fluctuate based on the utilization of the credit facility. Interest will generally be payable quarterly for loans bearing interest based on the alternative base rate and at the applicable maturity date for LIBOR-based loans. We will be required to pay a fee of 0.5% per annum on the unused portion of the borrowing base under the credit facility. Borrowings under the credit facility will be available for, among other things, working capital and general corporate purposes. For additional details regarding the anticipated credit facility, see "Credit Agreement" beginning on page 219.

The board of directors of Atlas Energy's general partner believes, given the current makeup of its assets and market environment, that separating the natural gas and oil development and production assets and the partnership management business from the remainder of Atlas Energy's businesses is in the best interests of Atlas Energy and its unitholders and has concluded that the separation will provide each company with a number of opportunities and benefits, including the following:

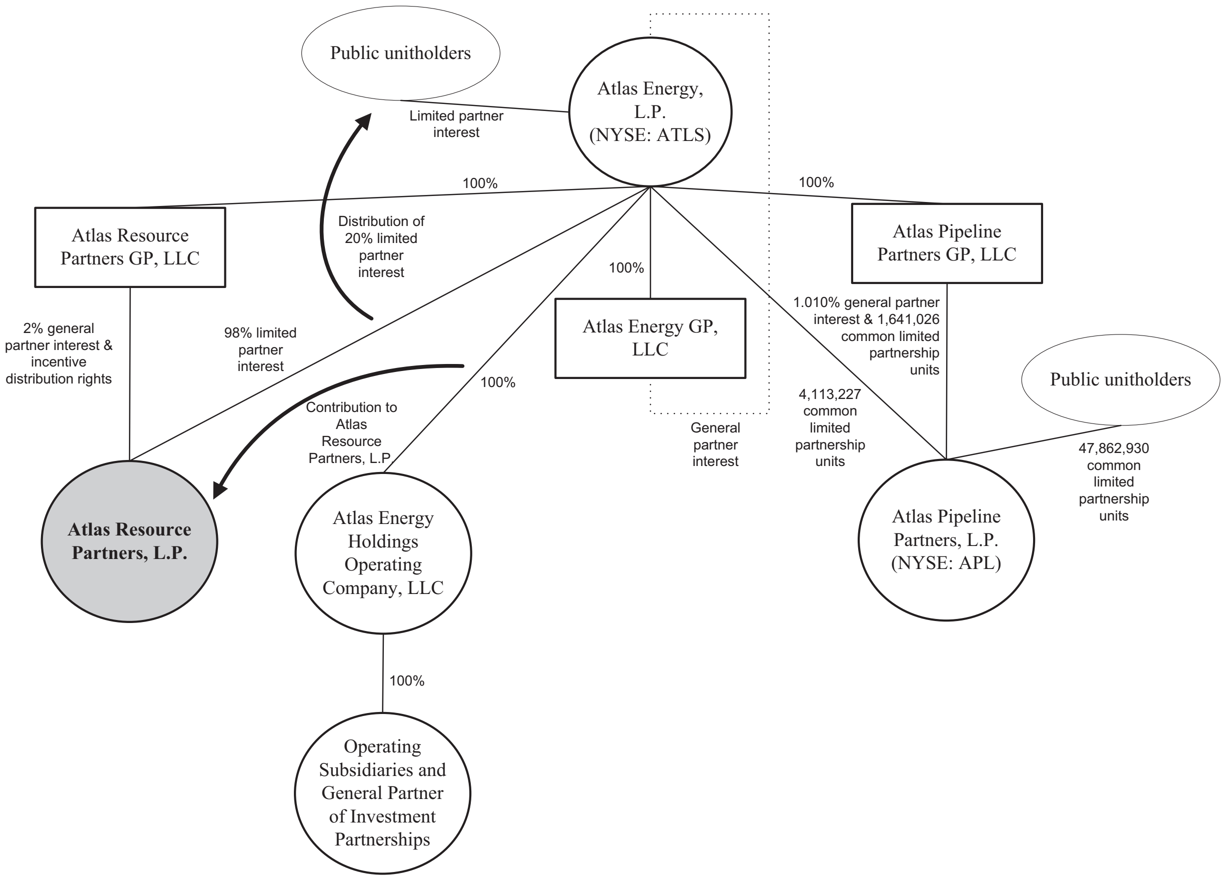
- The separation will facilitate deeper understanding by investors of the different businesses of Atlas Energy and Atlas Resource Partners, allowing investors to more transparently value the merits, performance and future prospects of each company, which could increase overall unitholder value;
- By 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 Atlas Resource Partners 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 Atlas Resource Partners 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 Atlas Energy and Atlas Resource Partners to gain access to financing because the financial community will be able to focus separately on each of their respective businesses, which have different investment and business characteristics and different potentials for financial returns;
- The separation and distribution will enable Atlas Resource Partners to provide employees dedicated to the business of Atlas Resource Partners with equity-based incentives linked solely to Atlas Resource Partners, as opposed to equity of Atlas Energy;
- If Atlas Resource Partners is able to increase its distributions, Atlas Energy unitholders could benefit from both Atlas Energy's indirect general partner interest in Atlas Resource Partners as well as its incentive distribution rights in Atlas Resource Partners;
- 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.

A discussion of some of the other opportunities and benefits that the board of directors of Atlas Energy's general partner considered in approving the separation is included elsewhere in this information statement.

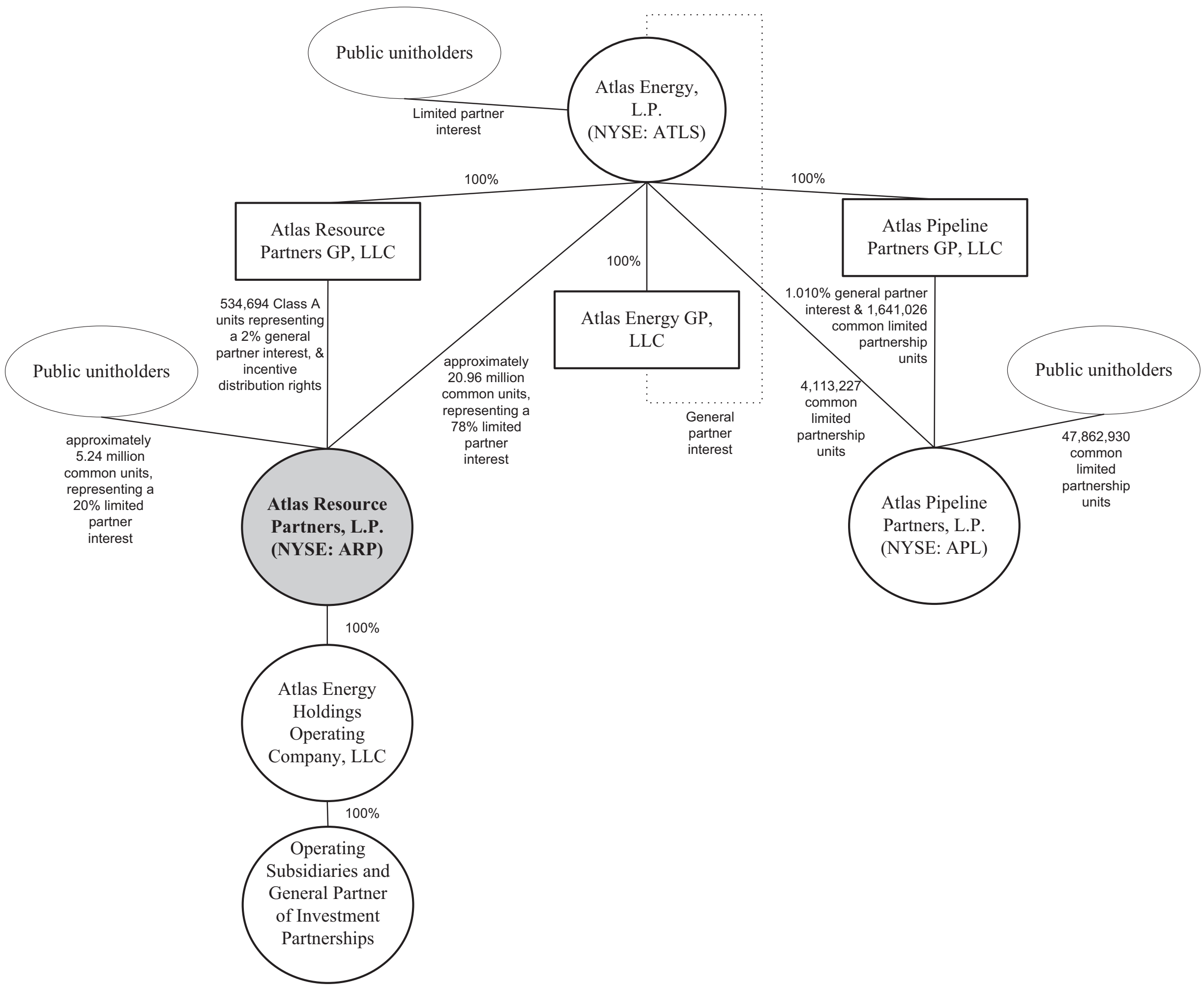
The distribution of our common units as described in this information statement is subject to the satisfaction or waiver of certain conditions. For more information, see the section entitled "The Separation and Distribution—Conditions to the Distribution" beginning on page 65.

Organizational Chart

The following chart shows the organization and ownership of Atlas Energy and its primary subsidiaries and affiliates, including Atlas Resource Partners, prior to giving effect to the distribution and the related transactions.



The following chart shows our organization and ownership after giving effect to the distribution and the related transactions. All unit figures are approximate numbers and are based on the distribution of approximately 5.24 million common units of Atlas Resource Partners to the Atlas Energy unitholders.



Company Information

We were formed in Delaware in October 2011 for the purpose of holding substantially all of Atlas Energy's current natural gas and oil development and production assets and its partnership management business in connection with the separation and distribution described in this information statement. Prior to the contribution of our assets and businesses, we will have no operations other than activities taken in connection with the separation and distribution. The address of Atlas Resource Partners' principal executive offices is Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, PA 15275, and the phone number is (800) 251-0171. We intend to establish an Internet site at *www.atlasresourcepartners.com*. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this information statement.

Cash Distributions

The amount of distributions paid under our cash distribution policy and the decision to make any distribution will be determined by our general partner, taking into account the terms of our partnership agreement. We intend to make a minimum quarterly distribution of $0.40 per common and per class A unit to the extent we have sufficient available cash from operations after we establish appropriate cash reserves and pay fees and expenses, including payments to our general partner for reimbursement of costs and expenses it incurs on our behalf. We refer to this cash as "available cash," and we define its meaning in more detail in our partnership agreement and in "Cash Distribution Policy." Our general partner has broad discretion in establishing reserves. The cash reserves that our general partner may establish include reserves for future cash distributions on the common units, the class A units and incentive distribution rights. These reserves, which could be substantial, will reduce the amount of cash available for distribution to you. The minimum distribution is intended to reflect the level of cash that we expect to be available for distribution per common unit and class A unit for each quarter. There is no guarantee we will pay the minimum distribution, or any distribution, in any quarter. We would not have generated sufficient available cash on a pro forma basis to have paid the minimum distribution on all of our outstanding common units and class A units for the twelve months ended September 30, 2011.

Our general partner has adopted a policy that it will raise our quarterly cash distribution only when it believes that we have sufficient reserves and liquidity for the proper conduct of our business and can maintain the increased distribution level for a sustained period. While this is our current policy, our general partner may in its discretion alter the policy in the future. Our partnership agreement requires that, within 45 days after the end of each calendar quarter beginning with the quarter ending March 31, 2012, we distribute all of our available cash to holders of record of our units on the applicable record date. We will adjust the minimum quarterly distribution for the period from March 13, 2012 (the distribution date) through March 31, 2012 based on the actual length of the period.

The amount of available cash in any quarter may be greater or less than the aggregate amount associated with payment of the minimum quarterly distribution on all our common units and class A units.

In general, we will pay cash distributions in the following manner:

- first, 2% to holders of our class A units (which will be held by our general partner) and 98% to the holders of our common units, each pro rata, until each holder has received $0.40 per outstanding unit, which we refer to as the "minimum distribution";
- second, 2% to holders of our class A units and 98% to the holders of our common units, each pro rata, until each holder has received $0.46 per outstanding unit, which we refer to as the "first target distribution";
- third, 2% to the holders of our class A units and 85% to the holders of our common units, each pro rata, and 13% to the holder of the incentive distribution rights, which will initially be our general partner,

until each holder of our class A units and holder of our common units has received $0.50 per outstanding unit, which we refer to as the "second target distribution";

- fourth, 2% to the holders of our class A units and 75% to the holders of our common units, each pro rata, and 23% to the holder of the incentive distribution rights, until each holder of our class A units and holder of our common units has received $0.60 per outstanding unit, which we refer to as the "third target distribution"; and
- after that, 2% to the holders of our class A units and 50% to the holders of our common units, each pro rata, and 48% to the holder of the incentive distribution rights.

The class A units represent a 2% general partner interest in Atlas Resource Partners, and the holder of such 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 Atlas Resource Partners as one common unit, if we issue additional common units, we will also issue to our general partner, for no additional consideration and without a requirement to make any 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.

Incentive Distribution Rights

In addition to holding all our class A units, which represent a 2% general partner interest in us, our general partner holds all of our incentive distribution rights, which provides its holder with a right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after we have met specified target distribution levels, as described below. Our general partner may transfer its incentive distribution rights separately from its class A units, without the consent of the common unitholders. The table below summarizes the cash distributions attributable to our common units and class A units and the incentive distribution rights, at various distribution levels:

		Marginal percentage interest in distributions		
	Quarterly distribution level	Common units	Class A units	Incentive distribution rights
Minimum quarterly distribution per common and class A unit	$0.40	98.0%	2.0%	0.0%
First target distribution per common and class A unit	up to $0.46	98.0%	2.0%	0.0%
Second target distribution per common and class A unit	above $0.46 up to $0.50	85.0%	2.0%	13.0%
Third target distribution per common and class A unit	above $0.50 up to $0.60	75.0%	2.0%	23.0%
After that	above $0.60	50.0%	2.0%	48.0%

For a further discussion of the management incentive interests, please read the information set forth under the caption "Cash Distribution Policy—Incentive Distribution Rights" beginning on page 73.

Right to Reset Target Distribution Levels

The holder of our incentive distribution rights, which will initially be our general partner, has the right, at any time when it has received incentive distributions at the highest level to which it is entitled (48.0%) 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. Please read "Cash Distribution Policy—Right to Reset Incentive Distribution Levels" beginning on page 74.

Issuance of Additional Units

We can issue an unlimited number of additional units, including units that are senior to the common units, without the consent of our unitholders. Please read "Risk Factors—Risks Relating to Ownership of Our Common Units—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" beginning on page 49 and "Our Partnership Agreement—Issuance of Additional Securities" beginning on page 209.

Agreement to Be Bound by Partnership Agreement; Common Unit Voting Rights

By acquiring a common unit in the distribution or if you purchase or otherwise acquire a common unit, you will be admitted as a partner of our limited partnership and be deemed to have agreed to be bound by all of the terms of our partnership agreement. Pursuant to our partnership agreement, as a common unitholder, you will be entitled to vote on the following matters:

- specified amendments to our partnership agreement;
- merger of our company or the sale of all or substantially all of our assets; and
- dissolution of our company.

You will not be entitled to elect the members of the board of directors of our general partner, which will be determined by the sole equityholder of our general partner, Atlas Energy. Moreover, upon completion of the separation and the distribution, Atlas Energy will own approximately 20.96 million common units, which will represent 80.0% of the outstanding common units and an approximately 78.4% limited partner interest in us. This will give Atlas Energy the ability to determine virtually all matters submitted to a unitholder vote.

Limitations on Voting by Holders of More Than 20% of Our Common Units

Our limited partnership 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.

Limited Call Right

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 absolute 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:

- 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
- 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.

Upon completion of the separation and the distribution, Atlas Energy will own approximately 20.96 million common units, which will represent 80.0% of the outstanding common units and an approximately 78.4% limited partner interest in us. As a result, our general partner will have the right to exercise this limited call right. Following the distribution, you may be required to sell your common units at an undesirable time or price.

Estimated Ratio of Taxable Income to Distributions

We estimate that a U.S. holder who receives our common units in the distribution and holds such common units from the distribution date through the record date for distributions for the period ending December 31, 2011, will be allocated an amount of U.S. federal taxable income for that period that will be 50% or less of the cash distributed with respect to that period. We anticipate that after the taxable year ending December 31, 2011, the ratio of allocable taxable income to cash distributions to the unitholders will increase. Please read the summary in the section entitled “Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units” beginning on page 224.

SUMMARY HISTORICAL AND UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

We were formed in October 2011 and therefore do not have any historical financial statements. The following table presents summary historical condensed combined financial data for our predecessor, Atlas Energy E&P Operations, and summary pro forma condensed combined financial data for Atlas Resource Partners. "Atlas Energy E&P Operations" consists of the subsidiaries of Atlas Energy that hold Atlas Energy's natural gas and oil development and production assets and liabilities and its partnership management business, substantially all of which Atlas Energy has transferred, or will transfer prior to the distribution, to Atlas Resource Partners.

The summary historical condensed combined statement of operations data for the nine months ended September 30, 2011 and 2010 and the summary historical condensed combined balance sheet data as of September 30, 2011 have been derived from Atlas Energy E&P Operations' unaudited condensed combined financial statements included elsewhere in this information statement. The summary historical condensed combined statement of operations data for each of the fiscal years in the three-year period ended December 31, 2010 and the summary historical condensed combined balance sheet data as of December 31, 2010 and 2009 were derived from Atlas Energy E&P Operations' audited combined financial statements included elsewhere in this information statement. The unaudited combined financial statements have been prepared on the same basis as the audited combined financial statements and, in our opinion, include all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the information set forth herein.

The summary pro forma condensed combined statement of operations data for the nine months ended September 30, 2011 and 2010 and the year ended December 31, 2010, and the summary pro forma condensed combined balance sheet data as of September 30, 2011, were derived from our unaudited pro forma combined financial statements included elsewhere in this information statement, which have been adjusted to give effect to the following transactions:

- the contribution by Atlas Energy to us of the assets and liabilities that comprise our business;
- the issuance of 26,200,000 of our common units, of which approximately 5.24 million common units will be distributed to holders of Atlas Energy common units and the remaining approximately 20.96 million common units will be retained by Atlas Energy, and the issuance of 534,694 class A units to our general partner. This number of common units is based upon the number of Atlas Energy common units outstanding on February 28, 2012 and a distribution ratio of 0.1021 of a common unit of Atlas Resource Partners for each common unit of Atlas Energy; and
- the impact of a separation agreement between us and Atlas Energy and the provisions contained therein.

The summary pro forma condensed combined statements of operations data for the nine months ended September 30, 2011 and 2010 and the year ended December 31, 2010 assumes the separation and related transactions had occurred as of January 1, 2011, January 1, 2010 and January 1, 2010, respectively. The summary pro forma condensed combined balance sheet data assumes the separation and related transactions occurred on September 30, 2011. The assumptions used and pro forma adjustments derived from such assumptions are based on currently available information, and we believe such assumptions are reasonable under the circumstances.

The summary pro forma condensed combined financial data is not necessarily indicative of our results of operations or financial condition had the separation and our anticipated post-separation capital structure been completed on the dates assumed. Also, they may not reflect the results of operations or financial condition that would have resulted had we been operating as an independent, publicly traded company during such periods. In addition, they are not necessarily indicative of our future results of operations or financial condition. Further information regarding the pro forma adjustments listed above can be found within the "Atlas Resource Partners, L.P. Unaudited Pro Forma Condensed Combined Financial Statements" section of this information statement beginning on page F-2.

The summary historical condensed combined financial data presented below should be read in conjunction with Atlas Energy E&P Operations' audited and unaudited interim combined financial statements and accompanying notes, unaudited interim condensed combined financial statements and accompanying notes beginning on page F-12 and "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 99. The summary pro forma condensed combined financial data presented below should be read in conjunction with our unaudited pro forma combined financial statements included elsewhere in this information statement.

	Predecessor Historical					Atlas Resource Partners Pro Forma		
	Nine Months Ended September 30,		Years Ended December 31,			Nine Months Ended September 30,		Year Ended December 31,
	2011	2010 (Restated)	2010 (Restated)	2009 (Restated)	2008 (Restated)	2011	2010	2010
	(in thousands, except per share data)							
Statement of operations data:								
Revenues:								
Gas and oil production	$ 51,654	$ 70,816	$ 93,050	$112,979	$ 127,083	$ 51,654	$ 70,816	$ 93,050
Well construction and completion	64,336	176,685	206,802	372,045	415,036	64,336	176,685	206,802
Gathering and processing	14,048	11,414	14,087	18,839	19,098	14,048	11,414	14,087
Administration and oversight	5,073	7,473	9,716	15,554	19,277	5,073	7,473	9,716
Well services	15,051	15,589	20,994	17,859	18,513	15,051	15,589	20,994
Total revenues	150,162	281,977	344,649	537,276	599,007	150,162	281,977	344,649
Costs and expenses:								
Gas and oil production	11,953	16,863	23,323	25,557	25,104	11,953	16,863	23,323
Well construction and completion	54,754	149,724	175,247	315,546	359,609	54,754	149,724	175,247
Gathering and processing	16,377	16,499	20,221	25,269	19,098	16,377	16,499	20,221
Well services	6,077	7,691	10,822	9,330	10,654	6,077	7,691	10,822
General and administrative	12,275	8,536	11,381	15,832	13,074	12,275	8,536	11,381
Depreciation, depletion and amortization	24,019	31,929	40,758	43,712	39,781	24,019	31,929	40,758
Asset impairment	—	—	50,669	156,359	—	—	—	50,669
Total costs and expenses	125,455	231,242	332,421	591,605	467,320	125,455	231,242	332,421
Operating income (loss)	24,707	50,735	12,228	(54,329)	131,687	24,707	50,735	12,228
Loss on asset sales	—	(2,947)	(2,947)	—	—	—	(2,947)	(2,947)
Interest expense	—	—	—	—	—	(338)	(338)	(450)
Net income (loss)	$ 24,707	$ 47,788	$ 9,281	$ (54,329)	$ 131,687	$ 24,369	$ 47,450	$ 8,831
Other financial information:								
Adjusted EBITDA[1]	$ 48,726	$ 79,717	$100,708	$145,742	$ 171,468	$ 48,726	$ 79,717	$100,708
Balance sheet data (at period end):								
Property, plant and equipment, net	$526,634	$535,297	$508,484	$503,386	$ 616,257	$526,634		
Total assets	669,296	717,265	649,232	690,603	834,260	671,296		
Total debt, including current portion	—	—	—	—	—	2,000		
Total equity	469,376	377,223	381,882	351,586	515,622	469,376		
Cash flow data:								
Net cash provided by operating activities	$ 41,614	$100,096	$ 60,586	$192,201	$ 169,278			
Net cash used in investing activities	(36,270)	(70,506)	(92,423)	(98,393)	(262,153)			
Net cash provided by (used in) financing activities	54,642	(29,590)	31,837	(93,808)	92,875			
Capital expenditures	(36,270)	(70,716)	(93,608)	(99,302)	(264,125)			
Operating data[2]:								
Net production:								
Natural gas (mcfd)	31,687	36,610	35,855	38,644	32,791			
Oil (bpd)	296	391	373	427	423			
Natural gas liquids (bpd)	449	493	499	101	—			
Total (mcfed)	36,158	41,914	41,090	41,814	35,327			
Average sales price:								
Natural gas (per Mcf)[3]:								
Realized price, after hedge	$ 5.24	$ 7.15	$ 7.08	$ 7.54	$ 9.40			
Realized price, before hedge	$ 4.69	$ 4.74	$ 4.60	$ 4.04	$ 9.63			
Oil (per Bbl):								
Realized price, after hedge	$ 90.65	$ 75.66	$ 77.31	$ 71.34	$ 92.28			
Realized price, before hedge	$ 89.79	$ 69.07	$ 71.34	$ 57.41	$ 91.71			
Natural gas liquids realized price (per Bbl)	$ 48.43	$ 36.67	$ 37.78	$ 36.19	$ —			
Production costs (per Mcfe):								
Lease operating expenses[4]	$ 1.01	$ 1.27	$ 1.27	$ 1.10	$ 1.06			
Production taxes	0.05	0.03	0.04	0.03	0.03			
Transportation and compression	0.48	0.58	0.65	0.68	0.85			
Total	$ 1.55	$ 1.89	$ 1.96	$ 1.80	$ 1.94			

(1) We define Adjusted EBITDA as earnings before interest, taxes, depreciation, depletion and amortization, plus certain non-cash items such as compensation expenses associated with unit issuances to directors and employees of our general partner. Adjusted EBITDA is not a measure of performance calculated in accordance with GAAP. Although not prescribed under GAAP, we believe the presentation of Adjusted EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other companies that have different financing and capital structures or tax rates. Adjusted EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. Adjusted EBITDA, as we calculate it, may not be comparable to Adjusted EBITDA measures reported by other companies. Adjusted EBITDA is also a financial measurement that, with certain negotiated adjustments, will be utilized within our proposed new credit facility. In addition, Adjusted EBITDA does not represent funds available for discretionary use or the payment of distributions. The following reconciles our net income to Adjusted EBITDA for the periods indicated:

	Predecessor Historical					Atlas Resource Partners Pro Forma		
	Nine Months Ended September 30,		Years Ended December 31,			Nine Months Ended September 30,		Year Ended December 31,
	2011	2010 (Restated)	2010 (Restated)	2009 (Restated)	2008 (Restated)	2011	2010	2010
	(in thousands)							
Net income (loss)	$24,707	$47,788	$ 9,281	$ (54,329)	$131,687	$24,369	$47,450	$ 8,831
Depreciation, depletion and amortization	24,019	31,929	40,758	43,712	39,781	24,019	31,929	40,758
Asset impairment	—	—	50,669	156,359	—	—	—	50,669
Interest expense	—	—	—	—	—	338	338	450
Adjusted EBITDA	$48,726	$79,717	$100,708	$145,742	$171,468	$48,726	$79,717	$100,708

(2) "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.

(3) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010 and 2009. Including the effect of this subordination, the average realized gas sales price were $4.44 per Mcf ($3.89 per Mcf before the effects of financial hedging) and $5.78 per Mcf ($3.47 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to our Business—Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

(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. Including the effects of these costs, total lease operating expenses per Mcfe were $0.67 per Mcfe ($1.21 per Mcfe for total production costs) and $0.86 per Mcfe ($1.47 per Mcfe for total production costs for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to our Business—Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

SUMMARY RESERVE DATA

The following tables show our estimated net proved reserves based on reserve reports prepared by our independent petroleum engineers. You should refer to “Risk Factors” beginning on page 28, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” beginning on page 99, “Business—Natural Gas and Oil Reserves” beginning on page 131, and the summary reserve report included as Exhibit 99.2 to the registration statement of which this document forms a part in evaluating the material presented below.

	December 31, 2010	December 31, 2009
Reserve data:		
Estimated net proved reserves:		
Natural Gas (Bcf)	176.1	183.7
Oil (MMBbls)[1]	1.8	1.9
Total (Bcfe)	187.1	195.0
Proved developed (Bcfe)	148.4	151.3
Proved undeveloped (Bcfe)[2]	38.7	43.6
Proved developed reserves as % of total proved reserves	79%	78%
Standardized measure (in millions)[3]	**$236.6**	**$178.8**
Reserve natural gas and oil prices:		
Base product price[4]:		
Natural gas—per Mcf	$ 4.38	$ 3.87
Oil—per Bbl	$79.43	$61.18
Weighted average price[5]:		
Natural gas—per Mcf	$ 4.63	$ 4.14
Oil—per Bbl	$72.70	$55.04

(1) Includes less than 0.1 MMBbls of natural gas liquids proved reserves.

(2) Our ownership in these reserves is subject to reduction as we generally make capital contributions, which include 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 23% to 41%, and will effectively reduce our ownership interest in these reserves from 100% to our respective ownership interest as we make these contributions.

(3) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest and income tax expenses, or to depletion, depreciation and amortization. The future cash flows are discounted using an annual discount rate of 10%. Standardized measure does not give effect to commodity derivative contracts. Because we are a limited partnership, we are generally not subject to federal or state income taxes and thus make no provision for federal or state income taxes in the calculation of our standardized measure.

(4) The Base product price is the unweighted average of the first-day-of-the-month price for each month within the prior 12-month period as of the dates indicated.

(5) The 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 weighted average oil price is the Base product price, adjusted for local contracted gathering arrangements. Amounts shown do not include financial hedging transactions.

RISK FACTORS

You should carefully consider each of the following risk factors and all of the other information set forth in this information statement. The risk factors generally have been separated into five groups: (1) risks relating to our business, (2) risks relating to the separation, (3) risks relating to the ownership of our common units, (4) tax risks to unitholders and (5) risks relating to our ongoing relationship with Atlas Energy and its affiliates. Based on the information currently known to us, we believe that the following information identifies the most significant risk factors affecting our company in each of these categories of risks. However, the risks and uncertainties our company faces are not limited to those set forth in the risk factors described below. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business. In addition, past financial performance may not be a reliable indicator of future performance, and historical trends should not be used to anticipate results or trends in future periods.

If any of the following risks and uncertainties develops into actual events, these events could have a material adverse effect on our business, financial condition or results of operations. In such case, the trading price of our common units could decline.

Risks Relating to Our Business

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

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

- the level of domestic and foreign supply and demand;
- the price and level of foreign imports;
- the level of consumer product demand;
- weather conditions and fluctuating and seasonal demand;
- overall domestic and global economic conditions;
- political and economic conditions in natural gas and oil producing countries, including those in the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the impact of the U.S. dollar exchange rates on natural gas and oil prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental relations, regulations and taxation;
- the impact of energy conservation efforts;
- the cost, proximity and capacity of natural gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

In the past, the prices of natural gas and oil have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2010, the NYMEX Henry Hub natural gas index price ranged from a high of $6.01 per MMBtu to a low of $3.29 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $91.51 per Bbl to a low of $68.01 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 will operate in a highly competitive environment for acquiring properties and other natural gas and oil companies, attracting capital through our investment partnerships, contracting for drilling equipment and securing trained personnel. Our competitors may be able to pay more for natural gas and oil properties and drilling equipment and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Moreover, our competitors for investment capital may have better track records in their programs, lower costs or stronger relationships with participants in the oil and gas investment community than we do. All of these challenges could make it more difficult for us to execute our growth strategy. We may not be able to compete successfully in the future in acquiring leasehold acreage or prospective reserves or in raising additional capital.

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

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

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

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

Our key project areas are located in active drilling areas in the Appalachian Basin, and many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of natural gas in these areas.

Our operations will 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. Because we expect that we will distribute our available cash from operations to our unitholders each quarter in accordance with the terms of our partnership agreement, we expect that we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund any expansion and investment capital expenditures. As a result, 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 will limit 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 will 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 investment partnerships will be marketed by a subsidiary of Chevron pursuant to an operating agreement between the parties. To the extent Chevron reduces the amount of natural gas they purchase 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.

Our historical and pro forma financial information may not be representative of our future performance.

The historical financial information included in this document is derived from the historical financial statements of Atlas Energy. These audited historical financial statements were prepared in accordance with

GAAP. Accordingly, the historical financial information included in this document does not reflect what our results of operations and financial condition would have been had the separation and distribution occurred during the periods presented, or what our results of operations and financial condition will be in the future. In preparing the unaudited pro forma financial information included in this document, we have made adjustments to the historical financial information based upon currently available information and upon assumptions that our general partner believes are reasonable in order to reflect, on a pro forma basis, the impact of the items discussed in the unaudited pro forma financial statements and related notes. The estimates and assumptions used in the calculation of the pro forma financial information in this information statement may be materially different from our actual experience. Accordingly, the pro forma financial information included in this document does not purport to represent what our results of operations would actually have been had the transactions which are reflected in the unaudited pro forma financial statements actually taken place, nor does it represent what our results of operations would have been had we operated as a separate entity during the periods presented. The pro forma financial information also does not purport to represent what our results of operations and financial condition will be in the future, nor does the unaudited pro forma financial information give effect to any events other than those discussed in the unaudited pro forma financial statements and related notes.

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 will maintain insurance against various losses and liabilities arising from our operations, insurance against all operational risks will not be 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 the oil and natural gas reserves received from Atlas Energy in connection with the separation, 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 future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting the reserves we will acquire in connection with the distribution and economically finding or acquiring additional recoverable reserves. Our ability to find and acquire additional recoverable reserves to replace current and future production at acceptable costs depends on our generating sufficient cash flow from operations and other sources of capital, principally from the sponsorship of new investment partnerships, all of which are subject to the risks discussed elsewhere in this section.

A decrease in natural gas prices could subject our oil and gas properties to a non-cash impairment loss under U.S. generally accepted accounting principles.

U.S. generally accepted accounting principles require oil and gas properties and other long-lived assets to be reviewed for impairment whenever events or changes in circumstances indicated 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. Atlas Energy tests its 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 Atlas Energy’s own economic interests and its 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. Atlas Energy estimates 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, Atlas Energy uses financial and physical hedges for its production. We anticipate that we will assume all of these hedges in the separation or implement a similar hedging program following the separation. 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. Atlas Energy generally limits 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 for derivative contracts, increases in prices for natural gas and crude oil could result in non-cash balance sheet reductions.

The accounting standards regarding hedge accounting are complex, and even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our financial statements may reflect volatility due to these derivatives, even when there is no underlying economic impact at that point. Due to the mark-to-market accounting treatment for these contracts, we could recognize incremental hedge liabilities between reporting periods resulting from increases in reference prices for natural gas and crude oil, which could result in our recognizing a non-cash loss in our accumulated other comprehensive income and a consequently non-cash decrease in our shareholders' equity between reporting periods. Any such decrease could be substantial.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Commodity Futures Trading Commission has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the Commodity Futures Trading Commission will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements, 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 contracts to spin off some of their derivatives contracts to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral), 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 existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. 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 contracts 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 us, our financial condition, and our results of operations.

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 its 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 earnings and cash flows.

Properties that we acquire in connection with the separation 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 may be 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.

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 began in November 2011. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. 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 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 has been introduced before U.S. Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process, and similar legislation 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 other regulatory mechanism. 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 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. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by February 28, 2012. If finalized, these rules could 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" could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

On April 2, 2007, the U.S. Supreme Court ruled in *Massachusetts. v. EPA* that the federal Clean Air Act definition of "pollutant" includes carbon dioxide and other greenhouse gases, or GHGs, and, therefore, the EPA has the authority to regulate carbon dioxide emissions from automobiles. Thereafter, on December 15, 2009, the EPA published its findings that emissions of carbon dioxide, or CO_2, methane, and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings allowed the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA subsequently adopted two sets of regulations under the existing Clean Air Act that would require a reduction in emissions of GHGs from motor vehicles and certain stationary sources to obtain permits and employ technologies to reduce GHG emissions. The EPA published the motor vehicle final rule in May 2010 and it became effective January 2011 and applies to vehicles manufactured in model years 2012-2016. The EPA adopted the stationary source rule in May 2010, and it also became effective January 2011, applying first to the largest emitters of GHGs and providing the potential for application to smaller emitters in later years. Both rules remain the subject of several lawsuits filed by industry groups in the U.S. Court of Appeals for the District of Columbia Circuit. Additionally, the EPA requires reporting of GHG emissions from certain emission sources. In October 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. Furthermore, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. The final rule, which may be applicable to many of our facilities, will require reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security (ACES) Act that, among other things, would have established a cap-and-trade system to regulate greenhouse gas emissions and would have required an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The ACES Act did not pass the Senate, however, and so was not enacted by the 111th Congress. The U.S. Congress may consider a climate change bill in the future. In addition, almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG 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 GHG emission reduction goal is achieved. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

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 will 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 will utilize hydraulic fracturing, which results in water discharges 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 affect on our operations and financial performance. Our ability to remove 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.

Potential introduction of a severance tax or impact fee in Pennsylvania could materially increase our liabilities.

Although Pennsylvania has historically not imposed a severance tax relating to the extraction of natural gas, various legislation has been proposed since 2008 with a focus on the state's budget deficit. On February 9, 2012, the Pennsylvania Legislature passed HB 1950, which is expected to be signed into law. The new law would impose 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 discharges of pollutants into regulated bodies of water;
- 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
- 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 Old Atlas or Atlas Energy or at locations to which Old Atlas or Atlas Energy have sent waste for disposal, in each case that relate to assets that will be acquired by us in connection with the distribution.

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

We will be 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 will be 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 will 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 will be 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 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. 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.

Old Atlas sponsored limited and general partnerships to finance certain of their development drilling activities, including in connection with assets we have received from Atlas Energy. We expect that we will continue this practice after the distribution. 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. Old Atlas has raised $149.3 million, $353.4 million and $438.4 million in calendar years 2010, 2009 and 2008, respectively. In the future, we may not be successful in raising funds through these investment partnerships at the same levels that Old Atlas 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 Atlas Energy's and Old Atlas' historical track record of generating returns and tax benefits to the investors in their existing partnerships.

Investors may be less willing to rely on Atlas Energy's or Old Atlas' historical results in light of the distribution, in which case we may have difficulty in maintaining or increasing the level of investment partnership fundraising relative to the levels achieved by Atlas Energy and Old Atlas. 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 Atlas Energy and Old Atlas 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 such as those we will sponsor following the distribution, 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.

Our fee-based revenues may decline if we are unsuccessful in sponsoring 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, and we will be bound by this agreement following the distribution. Thus, our revenues from a particular partnership will decrease if we do not achieve the specified minimum return.

We may be exposed to financial and other liabilities as the managing general partner in investment partnerships.

We will serve, or one of our subsidiaries will serve, 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 are, or our subsidiary will be, contingently liable for the obligations of the partnerships to the extent that partnership assets or insurance proceeds are insufficient. Atlas Energy has 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, and we (or our subsidiary) will be bound by this agreement after the distribution.

Certain officers and directors of Atlas Energy, who also serve as officers and directors of our general partner, 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 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 and became an employee of Old Atlas 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.

Risks Relating to the Separation

We have no operating history as a separate public company, and our historical and pro forma financial information is not necessarily representative of the results that we would have achieved had we been the owner or operator of our assets and may not be a reliable indicator of our future results.

The historical and pro forma financial information included in this information statement does not necessarily reflect the financial condition, results of operations or cash flows that we would have achieved as a separate publicly traded company or as the owner or operator of our assets during the periods presented or those that we will achieve in the future, primarily as a result of the following factors:

- Prior to the separation, our assets were operated by Atlas Energy and, prior to February 2011, by Old Atlas, as part of its broader corporate organization, rather than as a separate company. Atlas Energy (and previously Old Atlas) or one of its affiliates performed various corporate functions for us and/or our assets, including, but not limited to, tax administration, cash management, accounting, information services, human resources, ethics and compliance programs, real estate management, investor and public relations, certain governance functions (including internal audit) and external reporting. Our historical financial results and the consolidated pro forma financial results reflect allocations of corporate expenses from Atlas Energy or Old Atlas for these and similar functions. These allocations may be less than the comparable expenses we would have incurred had we operated as a separate publicly traded company.
- Other significant changes may occur in our cost structure, management, financing and business operations as a result of our operations as a company separate from Atlas Energy managed by our general partner.

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.

Previous to this filing, we filed financial statements for Atlas Energy E&P Operations, which represents our predecessor business, that did not include general and administrative expenses for periods prior to February 17, 2011, the date of the acquisition of our principal assets and liabilities (which we refer to as the "Transferred Business") by Atlas Energy from Old Atlas. We 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. In this filing, 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 believe reflect the approximate general and administrative costs of our underlying business segments.

The failure to include these general and administrative expenses in our prior filing is considered a material weakness in 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 develop or 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 develop and 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 develop or 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 will receive from Atlas Energy in connection with the separation 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;
- supply of and demand for natural gas; and
- changes in governmental regulations or taxation.

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

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

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. For more information, see the section entitled “Certain Relationships and Related Transactions” beginning on page 191.

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 Atlas Resource Partners, 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 Atlas Resource Partners 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 Atlas Resource Partners 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 Atlas Energy and Atlas Resource Partners to gain access to financing because the financial community will be able to focus separately on each of their respective businesses, which have different investment and business characteristics and different potentials for financial returns;
- The separation and distribution will enable Atlas Resource Partners to provide employees dedicated to the business of Atlas Resource Partners with equity-based incentives linked solely to Atlas Resource Partners, as opposed to equity of Atlas Energy;
- If Atlas Resource Partners is able to increase its distributions, Atlas Energy unitholders could benefit from both Atlas Energy’s indirect general partner interest in Atlas Resource Partners 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.

The U.S. federal income tax consequences of the separation depend on the status of Atlas Energy as a partnership for U.S. federal income tax purposes on the date of the distribution. If the IRS were successful in asserting that Atlas Energy should be treated as a corporation for U.S. federal income tax purposes on the date of the distribution, then Atlas Energy and unitholders of Atlas Energy who receive our common units in the distribution may be subject to significant tax liability.

The U.S. federal income tax consequences of the distribution depend on the status of Atlas Energy as a partnership for U.S. federal income tax purposes on the date of the distribution. We believe that Atlas Energy should be treated as a partnership for U.S. federal income tax purposes on the date of the distribution, and Atlas Energy files U.S. federal income tax returns on that basis. However, neither we nor Atlas Energy has requested, nor plan to request, a ruling from the IRS on this matter. The IRS could assert that Atlas Energy should be treated as a corporation for U.S. federal income tax purposes. If the IRS were successful in asserting that Atlas Energy should be treated as a corporation for U.S. federal income tax purposes, then Atlas Energy and unitholders of Atlas Energy who receive our common units in the distribution may be subject to significant tax liability.

If the IRS were successful in asserting that Atlas Energy should be treated as a corporation for U.S. federal income tax purposes on the date of the distribution, Atlas Energy would be subject to tax on gain, if any, that it would have recognized if it had sold our common units received by unitholders of Atlas Energy in the distribution in a taxable sale for their fair market value. In addition, in such case, each unitholder of Atlas Energy who receives our common units in the distribution would be treated as if the unitholder had received a distribution equal to the fair market value of our common units that were distributed to the unitholder, which generally would be treated as either taxable dividend income to the unitholder, to the extent of Atlas Energy's current or accumulated earnings and profits or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in its units of Atlas Energy, or taxable capital gain, after the unitholder's tax basis in such units of Atlas Energy is reduced to zero. Accordingly, taxation of Atlas Energy as a corporation on the date of the distribution could result in materially adverse tax consequences to Atlas Energy and unitholders of Atlas Energy who receive our common units in the distribution.

For further information, unitholders should read the read the section entitled "Certain U.S. Federal Income Tax Matters" beginning on page 220 and consult their own advisors concerning the U.S. federal, state, local and foreign tax consequences to them of the distribution, including in the event the IRS were successful in asserting that Atlas Energy should be treated as a corporation for U.S. federal income tax purposes on the date of the distribution.

Risks Relating to the Ownership of Our Common Units

If the unit price declines after the distribution, you could lose a significant part of your investment.

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

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

Sales of substantial amounts of our common units in the public market following the distribution, 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.

Following the completion of the distribution, Atlas Energy will own 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.

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 would not have generated sufficient available cash on a pro forma basis to have paid the minimum quarterly distribution on all of our outstanding common and class A units for the twelve months ended September 30, 2011.

The amount of available cash we will need to pay the minimum quarterly distribution for four quarters on the common units and class A units is approximately $42.8 million. If we had completed the transactions on October 1, 2010, pro forma available cash generated during the twelve months ended September 30, 2011 would have been approximately $42.3 million, which would have been insufficient by approximately $0.5 million to allow us to pay our minimum quarterly distribution on our common units and class A units during this period. For a calculation of our ability to make distributions to you based on our pro forma results for the twelve months ended September 30, 2011, please read "Cash Distribution Policy."

If we are unable to achieve the estimated Adjusted EBITDA set forth in "Cash Distribution Policy," we may be unable to pay the full, or any, amount of the minimum quarterly distribution on the common units, in which event the market price of our common units may decline substantially.

The estimated Adjusted EBITDA set forth in "Cash Distribution Policy" beginning on page 67, which is for the twelve-month period ending December 31, 2012. Our management has prepared this information and we have not received an opinion or report on it from any independent accountants. In addition, "Cash Distribution Policy" includes a calculation of estimated Adjusted EBITDA. The assumptions underlying this calculation are inherently uncertain and are subject to significant business, economic, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those expected. If we do not achieve the expected results, we may not be able to pay the full, or any, amount of the minimum quarterly distribution, in which event the market price of our common units may decline substantially.

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 may 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 proposed new 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.

We expect that our proposed new revolving credit facility will restrict, among other things, our ability to incur debt and pay distributions, and will require 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 proposed new 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 proposed new revolving credit facility are expected to be secured by substantially all of our assets, and if we are unable to repay our indebtedness under our new 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 has been no public market for our common units prior to the distribution. After the distribution, there will be approximately 5.24 million publicly traded common units outstanding (which figure excludes our common units that will be held by Atlas Energy immediately after the distribution). 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.

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. Please read "Cash Distribution Policy—Right to Reset Incentive Distribution Levels" beginning on page 74. 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. See "Our Partnership Agreement—Non-Citizen Assignees; Redemption" on page 216.

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. See "Our Partnership Agreement—Non-Taxpaying Holders; Redemption" beginning on page 216.

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.

As a limited partnership, we will qualify for, and intend to 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 composed 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.

Following the distribution, we intend to utilize the exemptions from the corporate governance requirements of the NYSE listing standards, including the foregoing. As a result, neither we or our general partner will have a nominating/governance committee or a compensation committee. Our general partner will initially have a majority of independent directors, but it may not have a majority of independent directors in the future. See "Management" beginning on page 142.

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. Upon completion of the separation and the distribution, Atlas Energy will own approximately 20.96 million common units, which will represent 80.0% of the outstanding common units and an approximately 78.4% limited partner interest in us. As a result, our general partner will have 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

For a discussion of the expected U.S. federal income tax consequences of owning and disposing of our common units, see "Certain U.S. Federal Income Tax Matters" beginning on page 220.

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.

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

You 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. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from your 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 will 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. Please read "Certain U.S. Federal Income Tax Matters" beginning on page 220 for a further discussion of the effect of the depreciation and amortization positions we will adopt.

Tax gain or loss on the disposition of our common units could be more or less than expected because prior distributions in excess of allocations of income will decrease your tax basis in your units.

If you sell any of your common units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that unit, will, in effect, become taxable income to you if the unit is sold at a price greater than your tax basis in that unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you. In addition, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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.

You may be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, you 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 you do not reside in any of those jurisdictions. You 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, you may be subject to penalties for failure to comply with those requirements. We will initially 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.

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 will own common units representing an approximately 78.4% limited partner interest and all of the equity of our general partner, which, in turn, will own class A units representing a 2% general partner interest in us following the distribution. Therefore, Atlas Energy will have effective control of us.

Upon completion of the distribution, Atlas Energy will own approximately 20.96 million common units representing an approximately 78.4% limited partner interest and all of the equity of Atlas Resource Partners GP, LLC, our general partner, which, in turn, will own 534,694 class A units representing a 2% general partner interest in us. Accordingly, Atlas Energy will possess 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 will be 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, including Atlas Energy unitholders receiving common units in the distribution.

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, you 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 will be publicly traded after the distribution, could prevent you from realizing any change-of-control premium on your 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 those of other unitholders. Atlas Energy's voting control may discourage transactions involving a change of control of our partnership, including transactions in which you as a holder of our common units might otherwise receive a premium for your 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 will have conflicts of interest, which may permit it to favor its own interests to your 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. Please read "Cash Distribution Policy—Operating Surplus and Capital Surplus—Definition of Operating Surplus—Capital Expenditures" beginning on page 70 for a discussion on when a capital expenditure constitutes a maintenance capital expenditure or an expansion or investment capital expenditure. This determination can affect the amount of cash that is distributed to our unitholders;

- 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, 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. Please read "Conflicts of Interest and Duties—No Fiduciary Duties" beginning on page 200.

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

Accordingly, Atlas Energy and its affiliates may acquire, develop or dispose of additional natural gas or oil properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. These factors may make it difficult for us to compete with Atlas Energy and its affiliates with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and accordingly cash available for distribution. This also may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders. Please read “Conflicts of Interest and Duties” beginning on page 195.

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.

The existence of all conflicts of interest disclosed in this information statement, and any actions of our general partner taken in connection with such conflicts of interest, have been approved by all of our unitholders pursuant to our partnership agreement. If our general partner seeks approval by the conflicts committee of the board of directors of our general partner of any such action or resolution, it will be presumed that, in making its decision, the conflicts committee acted in good faith. 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. See "Conflicts of Interest and Duties" beginning on page 195.

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 may have positions with Atlas Energy or its general partner. As of the date hereof, all of the individuals expected to be named as officers of our general partner (three of whom, Edward E. Cohen, Jonathan Z. Cohen and Matthew A. Jones, are also expected to be named as directors of our general partner), were officers and/or directors of Atlas Energy. 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.

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," "intend," "expect," "plan," "may," "will," "could," "should," "believe," "predict," "potential," "continue" and similar expressions are also intended to identify forward-looking 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:

- our ability to operate the assets we will acquire in connection with the distribution, and the costs of such operation;
- the potential that the pendency of the distribution will adversely affect the businesses to be acquired in connection with the distribution;
- 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 the reserves to be acquired by us in connection with the distribution 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, as described under "The Separation and Distribution—Reasons for the Separation and Distribution" beginning on page 62.

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 the "Risk Factors" section of this information statement beginning on page 28. 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 information statement, 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 the section entitled "Risk Factors" beginning on page 28, 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.

THE SEPARATION AND DISTRIBUTION

Background

In March 2011, management of Atlas Energy commenced a review, in light of its asset make-up and other factors, of the long-term strategy for its businesses in furtherance of its goal of delivering long-term value for its unitholders. On October 17, 2011, Atlas Energy announced that it intended to separate its existing natural gas and oil development and production assets and its partnership management business from the remainder of its businesses. Atlas Energy management and the board of directors of Atlas Energy's general partner determined that the partnership management business was best suited to remain with Atlas Energy's other natural gas and oil development and production assets, because Atlas Energy's primary drilling activity is currently conducted through the partnership management business and the fee-based income generated by the partnership management business may act as a hedge to fluctuations in cash flow from the development and production business caused by changes in commodity prices or other factors. The separation would occur through Atlas Energy's contribution of substantially all of its existing natural gas and oil development and production assets and its partnership management business to Atlas Resource Partners, L.P., a newly formed subsidiary, and through the distribution of approximately 5.24 million common units representing an approximately 19.6% limited partner interest in Atlas Resource Partners to Atlas Energy unitholders. On February 15, 2012, the board of directors of Atlas Energy's general partner approved the separation and distribution, with the distribution to occur on March 13, 2012 by way of a pro rata distribution of 0.1021 of a common unit of Atlas Resource Partners for each Atlas Energy common unit held of record at the close of business on February 28, 2012, the record date of the distribution.

Atlas Resource Partners was formed as a master limited partnership, which Atlas Energy management believed was the most appropriate structure due to the long-lived nature of the assets, their expected ability to generate steady cash flows over time, and the potential for tax-efficient growth through future acquisitions. The number of common units to be distributed and the other financial terms of the distribution were determined by management and the board of directors of Atlas Energy's general partner based on an analysis of the trading price per unit or share of selected comparable companies which were deemed relevant due to their business, structure and market capitalization.

Immediately following completion of the separation and distribution, Atlas Resource Partners will hold Atlas Energy's:

- 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;
- producing natural gas and oil assets properties (other than its rights of way in Ohio, ownership of which will not be transferred to Atlas Resource Partners, but which Atlas Resource Partners will have the right to use for development and production purposes), which assets and properties we will operate for development and production purposes; and
- 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.

Atlas Energy will hold (in addition to its own general partner):

- approximately 20.96 million common units representing an approximately 78.4% limited partner interest in Atlas Resource Partners;
- all of the equity of Atlas Resource Partners GP, LLC, the general partner of Atlas Resource Partners, which, in turn, will own 534,694 class A units representing a 2% general partner interest in us, as well as all of our incentive distribution rights;
- all of the equity of general partner of Atlas Pipeline Partners, L.P. (NYSE: APL) and its common units in Atlas Pipeline Partners, L.P.;
- a 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 Atlas Resource Partners will have the right to use such rights of way for development and production purposes.

The separation and distribution agreement will also provide that Atlas Energy will have the right to have access to Atlas Resource Partners' gathering assets in Ohio for any natural gas and oil production on commercially prevailing market terms to be agreed between Atlas Energy and Atlas Resource Partners.

The distribution of approximately 5.24 million common units in Atlas Resource Partners, as described in this information statement, is subject to the satisfaction or waiver of certain conditions. We cannot provide any assurances that the distribution will be completed or approved by the board of directors of Atlas Energy's general partner. For a more detailed description of these conditions, see the section entitled "The Separation and Distribution—Conditions to the Distribution" beginning on page 65.

Reasons for the Separation and Distribution

The board of directors of Atlas Energy's general partner believes, in light of its asset make-up and other factors, that separating Atlas Energy into two publicly traded companies is in the best interests of Atlas Energy and its unitholders and has concluded that the separation and distribution will provide each company with certain opportunities and benefits. A wide variety of factors were considered by the board of directors of Atlas Energy's general partner in evaluating the separation. Among other things, the board of directors considered the following opportunities and benefits:

- The separation will facilitate deeper understanding by investors of the different businesses of Atlas Energy and Atlas Resource Partners, 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 Atlas Resource Partners 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 limited partnership the general partner of which is owned by Atlas Energy. Current industry trends have created a significant opportunity for Atlas Resource Partners 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 Atlas Energy and Atlas Resource Partners to gain access to financing because the financial community will be able to focus separately on each of their respective businesses, which have different investment and business characteristics and different potentials for financial returns;
- The separation and distribution will enable Atlas Resource Partners to provide employees dedicated to the business of Atlas Resource Partners with equity-based incentives linked solely to Atlas Resource Partners, as opposed to equity of Atlas Energy;
- If Atlas Resource Partners is able to increase its distributions, Atlas Energy unitholders could benefit from both Atlas Energy's indirect general partner interest in Atlas Resource Partners as well as its incentive distribution rights in Atlas Resource Partners;
- 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.

Neither we nor Atlas Energy or any of their affiliates can assure you that, following the separation and distribution, any of the benefits described above or otherwise will be realized to the extent anticipated or at all.

The board of directors of Atlas Energy's general partner also considered a number of potentially negative factors in evaluating the separation, including potential loss of synergies (if any) from operating as one company, potential for increased costs, potential disruptions to the businesses as a result of the separation, potential for the two companies to compete with one another in the marketplace, risks of being unable to achieve the benefits expected to be achieved by the separation, risk that the plan of separation might not be completed, and both the one-time and ongoing costs of the separation. The board of directors of Atlas Energy's general partner concluded that notwithstanding these potentially negative factors, separation would be in the best interests of Atlas Energy and its unitholders.

In view of the wide variety of factors considered in connection with the evaluation of the separation and the complexity of these matters, the board of directors of Atlas Energy's general partner did not find it useful to, and did not attempt to, quantify, rank or otherwise assign relative weights to the factors considered. The individual members of the board of directors of Atlas Energy's general partner may have given different weights to each of the factors.

Formation of a Holding Company Prior to Our Distribution

We were formed as a limited partnership in Delaware in October 2011 for the purpose of holding substantially all of Atlas Energy's current natural gas and oil development and production assets and its partnership management business. As part of the plan to separate such businesses from its other businesses, Atlas Energy plans to transfer the equity interests of certain entities that operate its natural gas and oil development and production business and the partnership management business to us.

When and How You Will Receive Common Units in the Distribution

We expect that Atlas Energy will distribute approximately 5.24 million of our common units (other than common units sold as a result of fractional units) on March 13, 2012, the distribution date. The distribution will be made to all holders of record of Atlas Energy common units on February 28, 2012, the record date for the distribution. Atlas Energy's transfer agent and registrar, American Stock Transfer & Trust Company, LLC, which we refer to as "AST," will serve as transfer agent and registrar for the Atlas Resource Partners common units and as distribution agent in connection with the distribution of Atlas Resource Partners common units.

If you own Atlas Energy common units of the close of business on the record date, the Atlas Resource Partners common units that you are entitled to receive in the distribution will be issued electronically, as of the distribution date, to your account as follows:

- *Registered Unitholders*. If you own your Atlas Energy common units directly (either in book-entry form through an account at Atlas Energy's transfer agent, American Stock Transfer, and/or if you hold physical paper stock certificates), you will receive your Atlas Resource Partners common units by way of direct registration in book-entry form. Registration in book-entry form refers to a method of recording unit ownership when no physical paper share certificates are issued to unitholders, as is the case in this distribution.

  Commencing on or shortly after the distribution date, the distribution agent will mail to you an account statement that indicates the number of Atlas Resource Partners common units that have been registered in book-entry form in your name. If you have any questions concerning the mechanics of having your ownership of our common units registered in book-entry form, we encourage you to contact American Stock Transfer at the address set forth in this information statement.

- *Beneficial Unitholders*. Most Atlas Energy unitholders hold their Atlas Energy units beneficially through a bank or brokerage firm. In such cases, the bank or brokerage firm would be said to hold the units in "street name" and ownership would be recorded on the bank or brokerage firm's books. If you hold your Atlas Energy common units through a bank or brokerage firm, your bank or brokerage firm will credit your account for the Atlas Resource Partners common units that you are entitled to receive in the distribution. If you have any questions concerning the mechanics of having your common units held in "street name," we encourage you to contact your bank or brokerage firm.

Transferability of Our Common Units

Our common units that will be distributed in the distribution will be transferable without registration under the Securities Act except for common units received by persons who may be deemed to be our affiliates. Persons who may be deemed to be our affiliates after the distribution generally include individuals or entities that control, are controlled by or are under common control with us, which may include certain of our executive officers, directors or principal unitholders. Securities held by our affiliates will be subject to resale restrictions under the Securities Act. Our affiliates will be permitted to sell our common units only pursuant to an effective registration statement or an exemption from the registration requirements of the Securities Act, such as the exemption afforded by Rule 144 under the Securities Act.

Number of Our Common Units that You Will Receive

For each common unit of Atlas Energy that you own at the close of business on February 28, 2012, the record date, you will receive 0.1021 of our common units on the distribution date. No fractional common unit will be distributed. Instead, if you are a registered holder, the transfer agent will aggregate fractional units into whole units, sell the whole units in the open market at prevailing market prices and distribute the aggregate cash proceeds (net of discounts and commissions) of the sales pro rata (based on the fractional unit that such holder would otherwise be entitled to receive) to each holder who otherwise would have been entitled to receive a fractional unit in the distribution. The transfer agent, in its sole discretion, without any influence by Atlas Energy or us, will determine when, how, through which broker-dealer and at what price to sell the whole unit. Any broker-dealer used by the transfer agent will not be an affiliate of either Atlas Energy or us. Neither we nor Atlas Energy will be able to guarantee any minimum sale price in connection with the sale of these shares. Recipients of cash in lieu of fractional shares will not be entitled to any interest on the amounts of payment made in lieu of fractional shares.

The receipt of cash in lieu of fractional shares of our common units may be taxable to you for U.S. federal income tax purposes. See “Certain U.S. Federal Income Tax Matters” beginning on page 220 for a summary of the material U.S. federal income tax consequences of the distribution. We estimate that it will take approximately two weeks from the distribution date for the distribution agent to complete the distributions of the aggregate net cash proceeds. If you hold your Atlas Energy common units through a bank or brokerage firm, your bank or brokerage firm will receive, on your behalf, your pro rata share of the aggregate net cash proceeds of the sales and will electronically credit your account for your share of such proceeds.

Results of the Separation and Distribution

After the separation and distribution, we will be a separate, publicly traded company, but will remain controlled directly and indirectly by Atlas Energy. Immediately after the distribution, Atlas Energy will hold approximately 20.96 million of our common units, representing an approximately 78.4% limited partner interest in Atlas Resource Partners, and will own 100% of the equity of our general partner, Atlas Resource Partners GP, LLC. Atlas Resource Partners GP, LLC, in turn, will own 534,694 class A units representing a 2% general partner interest in us, as well as all of our incentive distribution rights. Immediately following the distribution, we expect to have approximately 207 unitholders of record, based on the number of registered holders of Atlas Energy common units as of February 28, 2012, and approximately 26,200,000 Atlas Resource Partners common units and 534,964 class A units outstanding. The actual number of common units to be distributed will be determined on the record date and will reflect any exercise of Atlas Energy options between the date that the board of directors of Atlas Energy’s general partner declares the distribution and the record date for the distribution.

Before the separation, we will enter into a separation and distribution agreement and other agreements with Atlas Energy to effect the separation and provide a framework for the relationships among us, Atlas Energy and our general partner after the separation. These agreements will provide for the allocation between Atlas Energy and Atlas Resource Partners of Atlas Energy’s assets, liabilities and obligations and will govern the relationships between Atlas Energy and certain of its affiliates, on the one hand, and Atlas Resource Partners and its subsidiaries, on the other hand, subsequent to the separation. For a more detailed description of these agreements, see “Certain Relationships and Related Transactions” beginning on page 191.

The distribution will not affect the number of outstanding Atlas Energy common units or any rights of Atlas Energy unitholders.

Market for Our Common Units

There is currently no public market for our common units. We have been approved to list our common units on the NYSE under the symbol "ARP." We have not and will not set the initial price of our common units. The initial price will be established by the public markets.

We cannot predict the price at which our common units will trade after the distribution. In fact, the combined trading prices after the separation of (1) our common units that each Atlas Energy unitholder will receive in the distribution and (2) the common units of Atlas Energy held by such unitholder at the record date may not equal the "regular-way" trading price of an Atlas Energy common unit immediately prior to the distribution. The price at which our common units trades may fluctuate significantly, particularly until an orderly public market develops. Trading prices for our common units will be determined in the public markets and may be influenced by many factors. See "Risk Factors—Risks Relating to the Ownership of Our Common Units—Sales of our common units following the distribution may cause our unit price to decline" on page 45.

Trading Between the Record Date and Distribution Date

Beginning on or shortly before the record date and continuing up to and including through the distribution date, we expect that there will be two markets in Atlas Energy common units: a "regular-way" market and an "ex-distribution" market. Atlas Energy common units that trade on the regular way market will trade with an entitlement to our common units that will be distributed pursuant to the distribution. Atlas Energy common units that trade on the "ex-distribution" market will trade without an entitlement to our common units that will be distributed pursuant to the distribution. Therefore, if you sell Atlas Energy common units in the "regular-way" market up to and including the distribution date, you will be selling your right to receive our common units in the distribution. If you own Atlas Energy common units at the close of business on the record date and sell those units on the "ex-distribution" market up to and including through the distribution date, you will receive our common units that you would be entitled to receive pursuant to your ownership as of the record date of the Atlas Energy common units.

Furthermore, beginning on or shortly before the record date and continuing up to and including through the distribution date, we expect that there will be a "when-issued" market in our common units. "When-issued" trading refers to a sale or purchase made conditionally because the security has been authorized but not yet issued. The "when-issued" trading market will be a market for our common units that will be distributed to Atlas Energy unitholders on the distribution date. If you owned Atlas Energy common units at the close of business on the record date, you would be entitled to receive a certain number of our common units distributed pursuant to the distribution. You may trade this entitlement to our common units, without the Atlas Energy common units that you own, on the "when-issued" market. On the first trading day following the distribution date, "when-issued" trading with respect to our common units will end, and "regular-way" trading will begin.

Conditions to the Distribution

We expect that the distribution will be effective on March 13, 2012, the distribution date, provided that, among other conditions described in this information statement, the following conditions shall have been satisfied or waived:

- no stop order is in effect for the registration statement of which this information statement forms a part;
- any required actions and filings with regard to state securities and blue sky laws of the United States (and any comparable laws under any foreign jurisdictions) shall have been taken and, where applicable, have become effective or been accepted;

- no order, injunction or decree issued by any court or agency of competent jurisdiction or other legal restraint or prohibition preventing consummation of the separation, distribution or any of the transactions contemplated by the separation and distribution agreement or any ancillary agreement, shall be in effect;
- the separation and the related transactions shall have occurred in accordance with the terms of the separation and distribution agreement;
- the separation and distribution agreement shall not have been terminated; and
- no other events or developments shall have occurred that, in the judgment of the board of directors of Atlas Energy L.P.'s general partner, would result in the distribution having a material adverse effect on Atlas Energy or its unitholders.

As of the date of this information statement, the following additional conditions have been satisfied:

- the SEC has declared effective our registration statement on Form 10, of which this information statement forms a part;
- our common units have been accepted for listing on the NYSE, subject to official notice of issuance; and
- the approval by the board of directors of Atlas Energy's general partner of the distribution on February 15, 2012.

The fulfillment of the foregoing conditions does not create any obligations on the part of Atlas Energy to effect the distribution, and the board of directors of Atlas Energy's general partner has reserved the right, in its sole discretion, to abandon, modify or change the terms of the distribution, including by accelerating or delaying the timing of the consummation of all or part of the distribution, at any time prior to the distribution date. Atlas Energy does not intend to notify its unitholders of any modifications to the terms of the separation and distribution that, in the judgment of the board of directors of its general partner, are not material. For example, the board of directors of Atlas Energy's general partner might consider to be material such matters as significant changes to the distribution ratios, the assets to be contributed or the liabilities to be assumed in the separation. To the extent that the board of directors of Atlas Energy's general partner determines that any modifications by Atlas Energy changes the material terms of the distribution in any material respect, Atlas Energy will notify its unitholders in a manner reasonably calculated to inform them about the modification as may be required by law, by, for example, publishing a press release, filing a current report on Form 8-K, or circulating a supplement to the information statement.

CASH DISTRIBUTION POLICY

Set forth below is a summary of the significant provisions of our partnership agreement that relate to our cash distributions.

General

The amount of distributions paid under our cash distribution policy and the decision to make any distribution will be determined by our general partner in its discretion, taking into account the terms of our partnership agreement. Our cash distribution policy reflects a basic judgment, given our current asset base, that our unitholders will be better served by the distribution of our available cash (which is defined in our partnership agreement and is net of any expenses and reserves established by our general partner) than by our retaining such available cash. It is the current policy of our general partner that we should increase our level of quarterly cash distributions per unit only when, in its judgment, it believes that:

- we have sufficient reserves and liquidity for the proper conduct of our business; and
- we can maintain such an increased distribution level for a sustained period.

The amount of "available cash," which is defined in our partnership agreement, will be determined by our general partner for each calendar quarter after the completion of the distribution and will be based upon recommendations from our management. Because we believe that we will generally finance any expansion capital expenditures and investment capital expenditures from external financing sources, we believe that our investors are best served by our distributing all of our available cash. In addition, because we are not subject to entity-level U.S. federal income tax as a partnership, we have more cash to distribute to you than would be the case if we were subject to U.S. federal income tax. Our cash distribution policy is consistent with the terms of our partnership agreement, which requires that we distribute all of our available cash.

Minimum Quarterly Distributions

We currently intend to distribute to the holders of our common units and class A units on a quarterly basis at least a minimum quarterly distribution of $0.40 per unit, or $1.60 per unit per year, to the extent we have sufficient available cash after we establish appropriate reserves and pay fees and expenses, including payments to our general partner in reimbursement of costs and expenses it incurs on our behalf. Our minimum quarterly distribution is intended to reflect the level of cash that we expect to be available for distribution per common unit and class A unit each quarter. There is no guarantee that we will pay the minimum quarterly distribution, or any distribution, in any quarter, and we will be prohibited from making any distributions to unitholders if it would cause an event of default or an event of default is existing under our proposed credit agreement. If we had completed the separation and distribution on October 1, 2010, the amount of pro forma available cash generated during the twelve months ended September 30, 2011 would have been insufficient by approximately $0.5 million to pay the minimum distribution on all our common units and class A units.

It is the current policy of our general partner that we should raise our quarterly cash distribution only when our general partner believes that:

- we have sufficient reserves and liquidity for the proper conduct of our business; and
- we can maintain such an increased distribution level for a sustained period.

While this is our current policy, our general partner may alter the policy in the future when and if it determines such alteration to be appropriate.

Quarterly Distributions of Available Cash

Our partnership agreement requires that we make distributions of all available cash (as defined in our partnership agreement) within 45 days after the end of each quarter, beginning with the quarter ending March 31, 2012, to holders of record on the applicable record date.

For these purposes, "available cash" generally means, for any of our fiscal quarters:

- all cash on hand at the end of the quarter (including amounts available for working capital purposes under a credit facility, commercial paper facility or other similar financing arrangement),
- *less* the amount of cash reserves established by our general partner at the date of determination of available cash for the quarter in order to:
  - provide for the proper conduct of our business (including reserves for working capital, operating expenses, future capital expenditures and credit needs and potential acquisitions);
  - comply with applicable law and any of our debt instruments or other agreements; or
  - provide funds for distributions to (1) our unitholders for any one or more of the next four quarters or (2) with respect to our incentive distribution rights (provided that our general partner may not establish cash reserves for future distributions on our common units and class A units unless it determines that the establishment of such reserves will not prevent us from distributing the minimum distribution on all common units and class A units);
- *plus*, if our general partner so determines, all or any portion of cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

Working capital borrowings are borrowings that are made under our proposed new credit facility or another arrangement and used solely for working capital purposes or to pay distributions to unitholders.

Operating Surplus and Capital Surplus

General

All cash we distribute to unitholders will be characterized as either "operating surplus" or "capital surplus." Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Definition of Operating Surplus

Operating surplus generally means:

- $60 million (as described below); *plus*
- all of our cash receipts after the separation, including working capital borrowings but excluding cash from (1) borrowings that are not working capital borrowings, (2) sales of equity and debt securities and (3) sales or other dispositions of assets outside the ordinary course of business; *plus*
- working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; *plus*
- cash distributions paid on equity securities that we may issue after the separation to finance all or a portion of the construction, acquisition, development, replacement or improvement of a capital asset (such as equipment or reserves) during the period beginning on the date that we enter into a binding obligation to commence the construction, acquisition, development or improvement of a capital improvement or replacement of a capital asset and ending on the earlier to occur of the date the capital improvement or capital asset begins producing in paying quantities, the date it is placed into service or the date that it is abandoned or disposed of; *plus*

- cash distributions paid (including incremental incentive distributions) on equity issued to pay the construction period interest on debt incurred (including periodic net payments under related interest rate swap arrangements), or to pay construction period distributions on equity issued, to finance the capital improvements or capital assets referred to above; *less*
- our operating expenditures (as defined below); *less*
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures; *less*
- all working capital borrowings not repaid within 12 months after having been incurred or repaid within such twelve-month period with the proceeds of additional working capital borrowings; *less*
- any cash loss realized on disposition of an investment capital expenditure.

If a working capital borrowing, which increases operating surplus, is not repaid during the twelve-month period following the borrowing, it will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will not be treated as a reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

Operating expenditures is defined in our partnership agreement, and generally means all of our cash expenditures, including but not limited to:

- taxes;
- reimbursement of expenses to our general partner and its affiliates;
- payments made in the ordinary course of business on hedge contracts;
- director and officer compensation;
- repayment of working capital borrowings;
- debt service payments; and
- estimated maintenance capital expenditures,

Operating expenditures, however, do not include:

- repayment of working capital borrowings previously deducted from operating surplus pursuant to the penultimate bullet point of the definition of operating surplus when the repayment actually occurs;
- payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness, other than working capital borrowings;
- expansion capital expenditures;
- actual maintenance capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions;
- distributions to our unitholders and distributions with respect to our incentive distribution rights; or
- repurchases of equity interests except to fund obligations under employee benefit plans.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our unitholders. For example, it includes a provision that will enable us, if we choose, to distribute as operating surplus up to $60 million of cash that we receive in the future from non-operating sources, such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including in the definition of operating surplus certain cash distributions on equity securities would be to increase operating surplus by the amount of the cash distributions. As a result, we may also distribute as operating surplus up to the amount of the cash distributions we receive from non-operating sources.

None of actual maintenance capital expenditures, investment capital expenditures or expansion capital expenditures are subtracted from operating surplus. Because actual maintenance capital expenditures, investment capital expenditures and expansion capital expenditures include interest payments (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all of the portion of the construction, acquisition, development, replacement or improvement of a capital asset (such as equipment or reserves) during the period from when we enter into a binding commitment to commence the construction, acquisition, development or improvement of a capital asset or replacement of a capital asset until the earlier to occur of the date any such capital asset is placed into service or the date that it is abandoned or disposed of, such interest payments and equity distributions are also not subtracted from operating surplus (except, in the case of maintenance capital expenditures, to the extent such interest payments and distributions are included in estimated maintenance capital expenditures).

Capital Expenditures

Estimated maintenance capital expenditures reduce operating surplus, but expansion capital expenditures, actual maintenance capital expenditures and investment capital expenditures do not.

Maintenance Capital Expenditures. Maintenance capital expenditures are those capital expenditures we expect to make on an ongoing basis to maintain our current production levels over the long term. We expect that a primary component of maintenance capital expenditures will be capital expenditures associated with the replacement of equipment and oil and natural gas reserves (including non-proved reserves attributable to undeveloped leasehold acreage and other similar assets), whether through the development, exploitation and production of an existing leasehold or the acquisition or development of a new oil or natural gas property, including to offset expected production declines from producing properties. Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all or any portion of a replacement asset that is paid in respect of the period beginning on the date that we enter into a binding obligation to commence construction or development of the replacement asset and ending on the earlier to occur of the date the replacement asset is placed into service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Because our maintenance capital expenditures can be irregular, the amount of our actual maintenance capital expenditures may differ substantially from period to period, which could cause similar fluctuations in the amounts of operating surplus, adjusted operating surplus and cash available for distribution to our unitholders if we subtracted actual maintenance capital expenditures from operating surplus. To address this issue, our partnership agreement will require that an estimate of the average quarterly maintenance capital expenditures (including estimated plugging and abandonment costs) necessary to maintain our asset base over the long term be subtracted from operating surplus each quarter as opposed to the actual amounts spent. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by the board of directors of our general partner at least once a year. We will make the estimate at least annually and whenever an event occurs that is likely to result in a material adjustment to the amount of future estimated maintenance capital expenditures, such as a major acquisition or the introduction of new governmental regulations that will impact our business. Any adjustment to this estimate will be prospective only. For a discussion of the amounts we have allocated toward estimated maintenance capital expenditures, please read "Cash Distribution Policy—Estimated Cash Available for Distribution" beginning on page 84.

The use of estimated maintenance capital expenditures in calculating operating surplus will have the following effects:

- it will reduce the risk that maintenance capital expenditures in any one quarter will be large enough to render operating surplus less than the minimum quarterly distribution to be paid on all the units for that quarter;
- it will increase our ability to distribute as operating surplus cash we receive from non-operating sources;
- in quarters where estimated maintenance capital expenditures exceed actual maintenance capital expenditures, it will be more difficult for us to raise our distributions above the minimum quarterly distribution, because the amount of estimated maintenance capital expenditures will reduce the amount of cash available for distribution to our unitholders, even in quarters where there are no corresponding actual capital expenditures; conversely, the use of estimated maintenance capital expenditures in calculating operating surplus will have the opposite effect for quarters in which actual maintenance capital expenditures exceed our estimated maintenance capital expenditures; and
- it will be more difficult for us to raise our distribution above the minimum quarterly distribution and pay incentive distribution rights.

Expansion Capital Expenditures

Expansion capital expenditures are those capital expenditures that we expect will increase the production of our and gas properties over the long term. Examples of expansion capital expenditures include the acquisition of reserves or equipment, the acquisition of new leasehold interests, or the development, exploitation and production of an existing leasehold interest, to the extent such expenditures are incurred to increase the production of our oil and gas properties over the long term. Expansion capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all or any portion of a capital improvement that is paid in respect of the period beginning on the date that we enter into a binding obligation to commence construction or development of the capital improvement and ending on the earlier to occur of the date the capital improvement is placed into service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered expansion capital expenditures.

Investment Capital Expenditures

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of our undeveloped properties in excess of the maintenance of our asset base, but which are not expected to expand our asset base for more than the short term.

Capital expenditures that are made in part for maintenance capital purposes and in part for investment capital or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by the board of directors of our general partner based upon its good faith determination.

Definition of Capital Surplus

Capital surplus is defined in our partnership agreement as any distribution of available cash in excess of our cumulative operating surplus. Accordingly, capital surplus would generally be generated by:

- borrowings (including sales of debt securities) other than working capital borrowings;
- sales of debt and equity securities; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other assets disposed of in the ordinary course of business or as part of normal retirement or replacement of assets.

Characterization of Cash Distributions

We treat all available cash distributed as distributed from operating surplus until the sum of all available cash distributed since we began operations equals our total operating surplus from the date that we began operations until the end of the quarter that immediately preceded the distribution. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As described above, operating surplus includes up to $60 million which does not reflect actual cash on hand that is available for distribution to our unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to this amount of cash we receive in the future from non-operating sources such as asset sales, issuances of securities and borrowings that would otherwise be distributed as capital surplus. We do not currently anticipate that we will make any distributions from capital surplus.

Distributions of Available Cash from Operating Surplus

We will make distributions of available cash from operating surplus for any quarter in the following manner:

- first, 2% to holders of our class A units (which will be held by our general partner) and 98% to the holders of our common units, each pro rata, until each holder has received $0.46 per outstanding unit, which we refer to as the "first target distribution"; and
- after that, in the manner described in "Cash Distribution Policy—Incentive Distribution Rights" beginning on page 73.

Adjusted operating surplus for any period generally means operating surplus generated during that period, less:

1. any net increase in working capital borrowings with respect to that period; and
2. any net decrease in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period,

and plus:

3. any net decrease in working capital borrowings made with respect to that period;
4. any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium; and
5. any net decrease made in subsequent periods in cash reserves for operating expenditures initially established with respect to such period to the extent such decrease results in a reduction of adjusted operating surplus in subsequent periods pursuant to item 2 above.

Operating surplus generated during a period is equal to the difference between:

- the operating surplus determined at the end of that period; and
- the operating surplus determined at the beginning of that period.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive increasing amounts of quarterly distributions of available cash from operating surplus after we have made payments in excess of the first target distribution and the tests described below have been met. Our general partner currently holds all of the incentive distribution rights, but may transfer these rights separately from its general partner interest in us, without the consent of the unitholders.

We will make incentive distributions to our general partner for any quarter in which we have distributed available cash from operating surplus to our unitholders in an amount equal to the first target distribution, as follows:

- first, 2% to holders of our class A units (which will be held by our general partner) and 98% to the holders of our common units, each pro rata, until each holder has received $0.40 per outstanding unit, which we refer to as the "minimum distribution";
- second, 2% to holders of our class A units and 98% to the holders of our common units, each pro rata, until each holder has received $0.46 per outstanding unit, which we refer to as the "first target distribution";
- third, 2% to the holders of our class A units and 85% to the holders of our common units, each pro rata, and 13% to the holder of the incentive distribution rights, which will initially be our general partner, until each holder of our class A units and holder of our common units has received $0.50 per outstanding unit, which we refer to as the "second target distribution";
- fourth, 2% to the holders of our class A units and 75% to the holders of our common units, each pro rata, and 23% to the holder of the incentive distribution rights, until each holder of our class A units and holder of our common units has received $0.60 per outstanding unit, which we refer to as the "third target distribution"; and
- after that, 2% to the holders of our class A units and 50% to the holders of our common units, each pro rata, and 48% to the holder of the incentive distribution rights.

The class A units represent a 2% general partner interest in Atlas Resource Partners, and the holder of such units will be entitled to 2% of our cash distributions, without any requirement to make a capital contribution 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 Atlas Resource Partners 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.

The following table illustrates the percentage allocations of the available cash from operating surplus between the unitholders and the owner of our incentive distribution rights up to various distribution levels. The amounts set forth under "Marginal percentage interest in distributions" are the percentage interests of our common unitholders and the holders of our incentive distribution rights in any available cash from operating surplus that we distribute up to and including the corresponding amount in the column "Quarterly distribution level," until available cash from operating surplus that we distribute reaches the next distribution level, if any. The percentage interests shown for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

		Marginal percentage interest in distributions		
	Quarterly distribution level	Common units	Class A units	Incentive distribution rights
Minimum quarterly distribution per common and class A unit	$0.40	98.0%	2.0%	0.0%
First target distribution per common and class A unit	up to $0.46	98.0%	2.0%	0.0%
Second target distribution per common and class A unit	above $0.46 up to $0.50	85.0%	2.0%	13.0%
Third target distribution per common and class A unit	above $0.50 up to $0.60	75.0%	2.0%	23.0%
After that	above $0.60	50.0%	2.0%	48.0%

Right to Reset Incentive Distribution Levels

The holder of our incentive distribution rights, which will initially be our general partner, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. 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 right.

The right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions are based may be exercised, without approval of our unitholders or the conflicts committee of the board of directors of our general partner, at any time when we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for the prior four consecutive fiscal quarters. The reset minimum quarterly distribution amount and target distribution levels are described below and will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset and there will be no incentive distributions paid under the reset target distribution levels. We anticipate that the holder of our incentive distribution rights would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to such holder.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment of incentive distribution payments based on the target cash distributions prior to the reset, the holder of our incentive distribution rights will be entitled to receive a number of newly issued common units based on a predetermined formula described below that takes into account the "cash parity" value of the average cash distributions related to the incentive distribution rights received by such holder for the two quarters prior to the reset event, as compared to the average cash distributions per common unit during this period.

The number of common units that the holder of our incentive distribution rights would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to:

- the average amount of cash distributions received by the holder of our incentive distribution rights in respect of such rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election; *divided by*
- the average of the amount of cash distributed per common unit during each of these two quarters.

Following a reset election, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per class A unit and common unit for the two fiscal quarters immediately preceding the reset election (which amount we refer to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to be correspondingly higher such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

- *first*, 2% to holders of our class A units and 98% to the holders of our common units, each pro rata, until each holder receives an amount per unit equal to 115% of the reset minimum quarterly distribution for that quarter;
- *second*, 2% to the holders of our class A units and 85% to the holders of our common units, each pro rata, and 13% to our general partner, until each holder of our class A units and holder of our common units receives an amount per unit equal to 125% of the reset minimum quarterly distribution for the quarter;
- *third*, 2% to the holders of our class A units and 75% to the holders of our common units, each pro rata, and 23% to our general partner, until each holder of our class A units and holder of our common units receives an amount per unit equal to 150% of the reset minimum quarterly distribution for the quarter; and
- *thereafter*, 2% to the holders of our class A units and 50% to the holders of our common units, each pro rata, and 48% to our general partner.

The following table illustrates the percentage allocation of available cash from operating surplus between the unitholders and our general partner at various cash distribution levels (1) pursuant to the cash distribution provisions of our partnership agreement in effect at the closing of this distribution, as well as (2) following a hypothetical reset of the minimum quarterly distribution and target distribution levels based on the assumption that the average quarterly cash distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $0.80.

		Marginal percentage interest in distributions			
	Quarterly distribution level prior to reset	**Common units**	**Class A units**	**Incentive Distribution Rights**	**Quarterly distribution following hypothetical reset**
Minimum quarterly distribution per common and class A unit	$0.40	98.0%	2.0%	0.0%	$0.80(1)
First target distribution per common and class A unit	up to $0.46	98.0%	2.0%	0.0%	up to $0.92(2)
Second target distribution per common and class A unit	above $0.46 up to $0.50	85.0%	2.0%	13.0%	above $0.92(2) up to $1.00(3)
Third target distribution per common and class A unit	above $0.50 up to $0.60	75.0%	2.0%	23.0%	above $1.00(3) up to $1.20(4)
After that	above $0.60	50.0%	2.0%	48.0%	above $1.20(4)

(1) This amount is equal to the hypothetical reset minimum quarterly distribution.
(2) This amount is 115.0% of the hypothetical reset minimum quarterly distribution.
(3) This amount is 125.0% of the hypothetical reset minimum quarterly distribution.
(4) This amount is 150.0% of the hypothetical reset minimum quarterly distribution.

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner (assuming that it holds all of the incentive distribution rights), based on an average of the amounts distributed for a quarter for the two quarters immediately prior to the reset. The table assumes that immediately prior to the reset there would be 26,200,000 common units outstanding, 534,694 class A units outstanding and the average distribution to each common unit would be $0.80 per quarter for the two quarters prior to the reset.

			Cash distributions to general partner prior to reset			
	Quarterly distribution level prior to reset	Cash distributions to common unitholders prior to reset	Class A units	Incentive distribution rights	Total	Total Distributions
Minimum quarterly distribution per common and class A unit	$0.40	$10,480,000	$213,877	—	$ 213,877	$10,693,877
First target distribution per common and class A unit	up to $0.46	$ 1,572,000	$ 32,082	—	$ 32,082	$ 1,604,082
Second target distribution per common and class A unit	above $0.46 up to $0.50	$ 1,048,000	24,659	$ 160,282	$ 184,941	$ 1,232,941
Third target distribution per common and class A unit	above $0.50 up to $0.60	$ 2,620,000	69,867	$ 803,467	$ 873,334	$ 3,493,334
After that	above $0.60	$ 5,240,000	209,600	$5,030,400	$5,240,000	$10,480,000
		$20,960,000	$550,085	$5,994,149	$6,544,234	$27,504,234

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner (assuming that it holds all of the incentive distribution rights), with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there would be 33,688,936 common units outstanding and 687,529 class A units outstanding (including the issuance of additional class A units to maintain the 2% sharing ratio) and the average distribution to each common unit would be $0.80. The number of common units to be issued to our general partner (assuming that it holds all of the incentive distribution rights) upon the reset was calculated by dividing (1) the average of the amounts received by our general partner in respect of its incentive distribution rights for the two quarters prior to the reset as shown in the table above, or $5,991,149, by (2) the average available cash distributed on each common unit for the two quarters prior to the reset as shown in the table above, or $0.80.

			Cash distributions to general partner after reset			
	Quarterly distribution level after reset	Cash distributions to common unitholders after reset	Class A units	Incentive distribution rights	Total	Total Distributions
Minimum quarterly distribution per common and class A unit	$0.80	$26,951,149	$550,023	—	$550,023	$27,501,172
First target distribution per common and class A unit	up to $0.92	—	—	—	—	—
Second target distribution per common and class A unit	above $0.92 up to $1.00	—	—	—	—	—
Third target distribution per common and class A unit	above $1.00 up to $1.20	—	—	—	—	—
After that	above $1.20	—	—	—	—	—
		$26,951,149	$550,023	—	$550,023	$27,501,172

The holder of our incentive distribution rights will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the prior four consecutive fiscal quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement.

Distributions from Capital Surplus

We distribute available cash from capital surplus, if any, in the following manner:

- first, 98% to the holders of our common units and 2% to the holders of our class A units, each pro rata, until distributions have been paid on each common unit from capital surplus in an aggregate amount equal to the initial unrecovered unit price (as defined below); and
- after that, we will distribute all available cash from capital surplus, as if it were from operating surplus.

Our partnership agreement treats a distribution from capital surplus as the repayment of an investment in our units, which we refer to as the "unrecovered unit price." The initial "unrecovered unit price" will be equal to the average of the closing prices of an Atlas Resource Partners common unit on the NYSE for the five trading days immediately following the completion of the distribution. Any distributions from capital surplus after the distribution will reduce the unrecovered unit price. In addition, any distribution of capital surplus will also reduce the minimum quarterly distribution, the first target distribution, the second target distribution and the third target distribution, which we refer to in this document as "target distribution levels." Each of the target distribution levels will be reduced in connection with a distribution of capital surplus to an amount equal to the then-applicable target distribution level multiplied by a fraction, the numerator of which is the unrecovered unit price immediately prior to such distribution of capital surplus, and the denominator of which is the unrecovered unit price immediately after such distribution of capital surplus.

After the minimum quarterly distribution and the target distribution levels have been reduced to zero, we will treat all distributions of available cash from all sources as if they were from operating surplus. Because the minimum quarterly distribution and the target distribution levels will have been reduced to zero, our general partner will then be entitled to receive 50% of all distributions of available cash in its capacity as general partner and holder of the incentive distribution rights, in addition to any distributions to which it may be entitled as a holder of units.

Distributions from capital surplus will not reduce the minimum quarterly distribution or target distribution levels for the quarter in which they are distributed.

Adjustment of Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjustments made upon a distribution of available cash from capital surplus, we will proportionately adjust the minimum quarterly distribution, target distribution levels and any other amounts calculated on a per unit basis upward or downward, as appropriate, if any combination or subdivision of common units occurs. For example, if a two-for-one split of the common units occurs, we will reduce the minimum quarterly distribution and the target distribution levels.

We will not make any adjustment for the issuance of additional common units for cash or property.

We may also adjust the minimum quarterly distribution and the target distribution levels if legislation is enacted or if existing law is modified or interpreted in a manner that causes us to become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes. In this event, we will reduce the minimum quarterly distribution and the target distribution levels for each quarter after that time to amounts equal to the product of:

- the minimum quarterly distribution and each of the target distribution levels, and

- one minus the sum of:
  - the highest marginal federal income tax rate which could apply to the partnership that is taxed as a corporation plus
  - the effective overall state and local income tax rate that would have been applicable in the preceding calendar year as a result of the new imposition of the entity level tax, after taking into account the benefit of any deduction allowable for federal income tax purposes for the payment of state and local income taxes, but only to the extent of the increase in rates resulting from that legislation or interpretation.

For example, assuming we are not previously subject to state and local income tax, if we became taxable as a corporation for federal income tax purposes and subject to a maximum marginal federal, and effective state and local, income tax rate of 40%, then we would reduce the minimum quarterly distribution and the target distribution levels to 60% of the amount immediately before the adjustment.

Distributions of Cash Upon Liquidation

When we commence dissolution and liquidation, we will sell or otherwise dispose of our assets and adjust the partners' capital account balances to reflect any resulting gain or loss. We will first apply the proceeds of liquidation to the payment of our creditors in the order of priority provided in our partnership agreement and by law. After that, we will distribute the proceeds to the unitholders and our general partner in accordance with their capital account balances, as so adjusted.

We maintain capital accounts in order to ensure that the partnership's allocations of income, gain, loss and deduction are respected under the Internal Revenue Code. The balance of a partner's capital account also determines how much cash or other property the partner will receive on liquidation of the partnership. A partner's capital account is credited with (increased by) the following items:

- the amount of cash and fair market value of any property (net of liabilities) contributed by the partner to the partnership, and
- the partner's share of "book" income and gain (including income and gain exempt from tax).

A partner's capital account is debited with (reduced by) the following items:

- the amount of cash and fair market value (net of liabilities) of property distributed to the partner, and
- the partner's share of loss and deduction (including some items not deductible for tax purposes).

Partners are entitled to liquidating distributions in accordance with their capital account balances.

Upon our liquidation, any gain, or unrealized gain attributable to assets distributed in kind, will be allocated to the partners in the following manner:

- first, to our partners who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;
- second, 2% to the holders of our class A units and 98% to the holders of our common units, each pro rata, until the capital account for each common unit is equal to the sum of:
  - the unrecovered unit price, and
  - the amount of the unpaid minimum quarterly distribution for the quarter during which our liquidation occurs;
- third, 2% to the holders of our class A units and 98% to holders of our common units, each pro rata, until there has been allocated under this paragraph an amount per unit equal to:
  - the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence, less

    - the cumulative amount per unit of any distribution of available cash from operating surplus in excess of the minimum quarterly distribution per unit that was distributed 2% to the holders of our class A units and 98% to the holders of our common units, each pro rata, for each quarter of our existence;
- fourth, 2% to the holders of our class A units and 85% to the holders of our common units, each pro rata, and 13% to the holder of the incentive distribution rights, until there has been allocated under this paragraph an amount per unit equal to:
    - the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence, less
    - the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that was distributed 2% to the holders of our class A units and 85% to the holders of our common units, each pro rata, and 13% to the holder of our incentive distribution rights for each quarter of our existence; and
- fifth, 2% to the holders of our class A units and 75% to the holders of our common units, each pro rata, and 23% to the holder of our incentive distribution rights, until there has been allocated under this paragraph an amount per unit equal to:
    - the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence, less
    - the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that was distributed 2% to the holders of our class A units and 75% to the holders of our common units, each pro rata, and 23% to the holder of our incentive distribution rights for each quarter of our existence; and
- after that, 50% to the holders of our common units and 2% to the holders of our class A units, each pro rata, and 48% to the holder of our incentive distribution rights.

Upon our liquidation, any loss will generally be allocated to our general partner and the unitholders in the following manner:

- first, 2% to the holders of our class A units and 98% to the holders of our common units, each pro rata, until the capital accounts of the common unitholders have been reduced to zero; and
- after that, 100% to our general partner.

In addition, we will make interim adjustments to the capital accounts at the time we issue additional equity interests or make distributions of property. We will base these adjustments on the fair market value of the interests or the property distributed and we will allocate any gain or loss resulting from the adjustments to the unitholders and our general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive interim adjustments to the capital accounts, we will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional equity interests or our distributions of property or upon our liquidation in a manner which results, to the extent possible, in the capital account balances of our general partner equaling the amount which would have been our general partner’s capital account balances if we had not made any earlier positive adjustments to the capital accounts.

Rationale for our Cash Distribution Policy

Our cash distribution policy reflects a basic judgment, given our current asset base, that our unitholders will be better served by our distributing our available cash rather than our retaining it. It is the current policy of our general partner that we should increase our level of quarterly cash distributions per unit only when, in its judgment, it believes that:

- we have sufficient reserves and liquidity for the proper conduct of our business, and

- we can maintain such an increased distribution level for a sustained period.

The amount of available cash will be determined by our general partner for each calendar quarter after the distribution and will be based upon recommendations from our management. Because we believe that we will generally finance any expansion capital expenditures and investment capital expenditures from external financing sources, we believe that our unitholders are best served by our distributing all of our available cash. Our cash distribution policy is consistent with the terms of our partnership agreement, which requires that we distribute all of our available cash quarterly. We are a recently formed limited partnership and have not made any cash distributions.

Restrictions and Limitations on Our Ability to Make Quarterly Distributions

We cannot guarantee that unitholders will receive quarterly cash distributions from us or that we can or will maintain any increases in our quarterly cash distributions. Our distribution policy may be changed at any time and is subject to certain restrictions, including:

- Other than the obligation under our partnership agreement to distribute available cash on a quarterly basis, which is subject to our general partner's authority to establish reserves and other limitations, our unitholders have no contractual or other legal right to receive distributions;
- Our general partner will have broad discretion to establish reserves for the prudent conduct of our business and for future cash distributions, and the establishment of those reserves could result in a reduction in cash distributions to you from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish or increase reserves made by our general partner in good faith will be binding on the unitholders. We intend to reserve a portion of our cash generated from operations to fund our exploration and development capital expenditures. Over a longer period of time, if our general partner does not set aside sufficient cash reserves or make sufficient cash expenditures to maintain our asset base, we will be unable to pay the minimum quarterly distribution from cash generated from operations and would therefore expect to reduce our distributions. If our asset base decreases and we do not reduce our distributions, a portion of the distributions may be considered a return of part of our unitholders investment in us as opposed to a return on our unitholders' investment;
- Our ability to make distributions of available cash will depend primarily on our cash flow from operations, which will fluctuate from quarter to quarter primarily based on commodity prices, production volumes, investor funds raised and the number of wells we drill. Although our partnership agreement provides for quarterly distributions of available cash, we have no prior history of making distributions to our unitholders;
- Even if we do not modify our cash distribution policy, the amount of distributions we pay and the decision to make any distribution will be determined by our general partner, taking into consideration the terms of our partnership agreement, our proposed new credit facility and any other debt agreements we may enter into in the future;
- Under Section 17-607 of the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets;
- If and to the extent our cash available for distribution materially declines, we may reduce our quarterly distribution in order to service or repay our debt or fund expansion capital expenditures;
- Our cash distribution policy may be subject to restrictions on distributions under our proposed new credit facility or other debt agreements that we may enter into in the future. Specifically, we anticipate that the agreement related to our proposed new credit facility will contain material financial tests and covenants that we will be required to satisfy. If we are unable to satisfy these restrictions, or if a default occurs under our new credit facility, we would be prohibited from making cash distributions to our unitholders notwithstanding our stated cash distribution policy;

- We may lack sufficient cash to pay distributions to our unitholders due to a number of factors, including 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, results of our hedging activities, the number of wells we drill, the amount of funds we raise through our investment partnerships, the level of our interest expense, principal and interest payments on our outstanding debt, tax expenses, and the level of our capital expenditures. See "Risk Factors" beginning on page 28 for information regarding these factors;
- Although our partnership agreement requires us to distribute our available cash, our partnership agreement may be amended with the approval of our general partner and a majority of our outstanding common units. Immediately after completion of the distribution, Atlas Energy will own outstanding common units representing an approximately 78.4% limited partner interest and will have the ability to amend our partnership agreement with the approval of our general partner;
- Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates for all direct and indirect expenses they incur on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of cash available to pay cash distributions to our unitholders;
- If and to the extent our cash available for distribution materially declines, we may reduce our quarterly distribution in order to service or repay our debt or fund growth capital expenditures;
- Our ability to make distributions to our unitholders depends on the performance of our operating subsidiaries and their ability to distribute cash to us. The ability of our operating subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations;
- All available cash distributed by us from any source will be treated as distributed from operating surplus until the sum of all available cash distributed by us equals the cumulative operating surplus from the date that we began operations through the end of the quarter immediately preceding that distribution. We anticipate that distributions from operating surplus will generally not represent a return of capital. However, operating surplus, as defined in our partnership agreement, includes certain components that represent non-operating sources of cash, including a $60 cash basket and working capital borrowings. Consequently, it is possible that distributions from operating surplus may represent a return of capital. For example, the $60 million cash basket would allow us to distribute as operating surplus cash proceeds we receive from non-operating sources, such as asset sales, issuances of securities and long-term borrowings, which would represent a return of capital. Distributions representing a return of capital could result in a corresponding decrease in our asset base. Additionally, any cash distributed by us in excess of operating surplus will be deemed to be capital surplus as the repayment of the initial investment in our units, which is similar to a return of capital. Distributions from capital surplus could result in a corresponding decrease in our asset base. We do not currently anticipate that we will make any distributions from capital surplus.

Our Cash Distribution Policy Limits Our Ability to Grow

Because we distribute our available cash, 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.

Our Ability to Grow is Dependent on Our Ability to Have Access to External Expansion Capital

Because we expect that we will distribute our available cash from operations to our unitholders each quarter in accordance with the terms of our partnership agreement, we expect that we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund any expansion and investment capital expenditures and any acquisitions. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we will distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand their ongoing operations. To the extent that we issue additional units in connection with any expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our quarterly distribution levels. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

Our Minimum Quarterly Distribution Rate

Upon completion of the distribution, our general partner will adopt a cash distribution policy pursuant to which we will pay a minimum quarterly distribution of $0.40 per common unit and class A unit for each complete quarter. Beginning with the quarter ending December 31, 2011, we will pay our quarterly distribution within 45 days after the end of each quarter ending March, June, September and December to holders of record on the record date established for the distribution. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. On December 31, 2011, we expect to pay a distribution to our unitholders equal to the minimum quarterly distribution prorated for the portion of the quarter ending December 31, 2011 following the distribution. These distributions will not be cumulative. Consequently, if we do not pay distributions on our common units and class A units with respect to any fiscal quarter, our unitholders will not be entitled to receive such payments in the future.

Our ability to make the minimum quarterly distribution pursuant to this policy will be subject to the factors described under the caption "Cash Distribution Policy—Restrictions and Limitations on Our Ability to Make Quarterly Distributions" beginning on page 80.

The following table sets forth the assumed number of outstanding common and class A units upon the closing of this distribution and the estimated aggregate amount of available cash from operating surplus, which we also refer to as cash available for distributions, we need to pay the minimum quarterly distribution on such units for one full quarter (at the initial rate of $0.40 per unit per quarter) and for four full quarters (at the initial rate of $1.60 per unit on an annualized basis):

	Number of Units	Minimum Quarterly Distribution	
		One Quarter	Four Quarters
Common units	26,200,000	$10,480,000	$41,920,000
Class A units	534,694(1)	213,878	855,512
Total	26,734,694	$10,693,878	$42,775,512

(1) The class A units will be entitled to 2% of all quarterly distributions that we make. The 534,694 class A units reflect the general partner's 2% ownership interest in our outstanding units (including common units and class A units), and such number will increase if we issue additional equity securities in the future.

The class A units will be entitled to 2% of all distributions that we make prior to our liquidation. The 2% sharing ratio of the class A units will not be reduced if we issue additional equity securities in the future.

We do not have a legal obligation to pay distributions at our minimum quarterly distribution rate or at any other rate. Our partnership agreement requires that we distribute all of our available cash quarterly. Available cash is defined to generally mean, for each fiscal quarter, cash generated from our business in excess of the amount our general partner determines is necessary or appropriate to provide for the conduct of our business, to comply with applicable law, any of our debt instruments or other agreements or to provide for future distributions to our unitholders for any one or more of the upcoming four quarters.

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuation based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement as described above. Our partnership agreement, including provisions contained therein requiring us to make cash distributions, may be amended by a vote of the holders of a majority of our common units. Following the distribution, Atlas Energy will own our general partner and will own common units representing an approximately 78.4% limited partnership in us. Accordingly, Atlas Energy will have the ability to amend our partnership agreement without the approval of any other unitholders, including to make certain amendments to our cash distribution policy.

In the sections that follow, we present in detail the basis for our belief that we will have sufficient available cash from operating surplus to pay the minimum quarterly distribution on all outstanding common units and class A units for each full calendar quarter through December 31, 2012. In those sections, we present the following two tables:

- "Estimated cash available for distribution," in which we present our estimated Adjusted EBITDA necessary for us to have sufficient cash available for distribution to pay distributions at the minimum quarterly distribution rate on all the outstanding common units and class A units for each quarter for the twelve months ending December 31, 2012. In the footnotes to this table, we present the significant assumptions and considerations underlying our belief that we will generate this estimated Adjusted EBITDA; and
- "Unaudited pro forma cash available for distribution," in which we present the amount of pro forma available cash we would have had available for distribution to our unitholders in the twelve months ended December 31, 2010 and September 30, 2011, based on our pro forma financial statements included elsewhere in this information statement. Our calculation of pro forma available cash in this table should only be viewed as a general indication of the amount of available cash that we might have generated had we been formed in an earlier period.

Financial Forecast

We do not as a matter of course make public projections of financial information. Our forecast information below presents, to our best knowledge and belief, our expected results of operations and cash flows for the twelve-month period ending December 31, 2012. Our forecast financial information reflects our judgment as of the date of this information statement of conditions we expect to exist and the course of action we expect to take during the twelve months ending December 31, 2012. The assumptions disclosed in the footnotes to the table under the caption "Cash Distribution Policy—Estimated Cash Available for Distribution—Estimated Adjusted EBITDA" on page 85 are those that we believe are significant to our forecasted information, but we cannot assure you that our forecast results will be achieved. There will likely be differences between our forecast and actual results, and those differences could be material. If we do not achieve the forecast, we may not be able to pay the full minimum quarterly distribution, or any distribution amount on our outstanding units.

Our forecast financial information is a forward-looking statement and should be read together with the historical and pro forma financial statements and the accompanying notes included elsewhere in this information statement and together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 99 and "Forward-Looking Statements" beginning on page 59. In the view of our management, however, such information was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the assumptions and considerations on which we base our belief that we can generate the estimated Adjusted EBITDA necessary for us to have sufficient available cash for distribution on the common units and class A units at the minimum quarterly distribution rate. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this information statement are cautioned not to place undue reliance on the prospective financial information.

Neither our independent registered public accounting firm, nor any other independent accountants, have compiled, examined or performed any procedures with respect to the prospective financial information contained in this section, nor have they expressed any opinion or any other form of assurance on such information or its achievability, and they assume no responsibility for, and disclaim any association with, the prospective financial information. The independent registered public accounting firm's reports included elsewhere in this information statement relate to the appropriately described historical financial information contained in this section. These reports do not extend to the tables and related information contained in this section and should not be read to do so. In addition, we did not prepare the forecasted financial information:

- with a view toward compliance with published guidelines of the SEC or the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of prospective financial information;
- in accordance with GAAP; or
- in accordance with procedures applied under the auditing standards of the Public Company Accounting Oversight Board (United States).

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update this financial forecast to reflect events or circumstances after the date in this information statement. Therefore, you should not place undue reliance on this information.

As a result of the factors described in "Cash Distribution Policy—Estimated Cash Available for Distribution" and in the footnotes to the table in that section, we believe we will be able to pay distributions at the minimum quarterly distribution rate of $0.40 per unit on all outstanding units for each full calendar quarter in the twelve or the period ending December 31, 2012.

Estimated Cash Available for Distribution

In order to pay the minimum quarterly distribution of $0.40 per unit per quarter to our unitholders for the twelve-month period ending December 31, 2012, our available cash for distribution must be at least approximately $42.8 million over that period. We estimate that our minimum Adjusted EBITDA for the twelve-month period ending December 31, 2012 must be at least $52.9 million in order to generate cash available for distribution to the holders of our common units and class A units of approximately $42.8 million over that period. We believe we will generate estimated Adjusted EBITDA of $61.5 million for the twelve months ending December 31, 2012. We refer to this amount as "Estimated Adjusted EBITDA." Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance calculated in accordance with GAAP, as those items are used to measure our operating performance, liquidity or ability to service debt obligations. If our estimate is not achieved, we may not be able to pay the minimum quarterly distribution on all our units. We can give you no assurance that our assumptions will be realized or that we will generate the $52.9 million in minimum Adjusted EBITDA required to pay the minimum quarterly distribution on all our units. There will likely be differences between our estimates and the actual results we will achieve and those differences could be material.

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any reserves by the board of directors of our general partner) the cash distributions we expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating operating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. EBITDA means the sum of net income (loss) plus:

- interest (income) expense;
- tax expense; and
- depreciation, depletion and amortization.

Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expense associated with unit issuances to directors and employees of our general partner.

In calculating the estimated cash available for distribution for the twelve-month period ending December 31, 2012, we have included amounts for estimated maintenance and expansion capital expenditures, as well as average borrowings of $5.8 million for the period to fund a portion of expansion capital expenditures. If we do not finance such expenditures with borrowings or issuances of additional common units, we would experience a shortfall in the amount of cash generated from our operations to pay both the aggregate cash distributions on our common units and make the expansion capital expenditures we expect to make. Our estimated maintenance, expansion and investment capital expenditures are as follows:

- Maintenance capital expenditures are capital expenditures that we expect to make on an ongoing basis to maintain our current levels of production over the long term. Examples of maintenance capital expenditures include plugging and abandonment costs and capital expenditures associated with the replacement of equipment and oil and natural gas reserves (including non-proved reserves attributable to undeveloped leasehold acreage), whether through the development, exploitation and production of an existing leasehold or the acquisition or development of a new oil or natural gas property, including to offset expected production declines from our producing properties.
- Expansion capital expenditures are those capital expenditures that we expect to make to increase the production of our natural gas and oil properties for the longer than short term. The expenditures would include amounts expended to increase the rate of development and production of our existing properties at a rate in excess of that necessary to offset our expected depletion rate decline of existing producing properties and which excess production or operating capacity we expect to extend for longer than the short term. Examples of expansion capital expenditures include the acquisition of reserves or equipment, the acquisition of new leasehold interests, or the development, exploitation and production of existing leasehold interests, to the extent such expenditures are incurred to increase our capital asset base. Our estimated expansion capital expenditures for the twelve months ending December 31, 2012 consist of capital expenditures we expect to make to drill and complete additional development wells in excess of the current level of production from our existing natural gas and oil properties.
- Investment capital expenditures are capital expenditures that are neither maintenance nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. For the twelve months ending December 31, 2012, we have not estimated any investment capital expenditures.

Estimated Adjusted EBITDA

You should read the information in the footnotes under the caption “Cash Distribution Policy—Estimated Cash Available for Distribution” beginning on page 84 for a discussion of the material assumptions underlying our belief that we will be able to generate Estimated Adjusted EBITDA of approximately $61.5 million. Our belief is based on those assumptions and reflects our judgment, as of the date of this information statement, regarding the conditions we expect to exist and the course of action we expect to take over the twelve-month period ending December 31, 2012. The assumptions we disclose below are those that we believe are significant to our ability to generate our Estimated Adjusted EBITDA. If our estimates prove to be materially incorrect, we may not be able to pay the minimum quarterly distribution or any amount on our outstanding units during the four calendar quarters ending December 31, 2012.

As shown in the table below, we have also assumed that if we achieve the Estimated Adjusted EBITDA, we would be permitted under the terms of our proposed new credit facility to make distributions to our unitholders. In addition, we have assumed that we will be permitted to make distributions at the minimum quarterly distribution rate under our proposed new credit facility. The terms of the proposed new credit facility have not yet been determined; however, we anticipate that our proposed new credit facility will limit our ability to pay distributions to the extent we are not in compliance with its terms.

When considering our Estimated Adjusted EBITDA, you should keep in mind the risk factors and other cautionary statements under the heading "Risk Factors" beginning on page 28 and elsewhere in this information statement. Any of these risk factors or the other risks discussed in this information statement could cause our financial condition and results of operations to vary significantly from those set forth in the table below.

The following table illustrates (i) our Estimated Adjusted EBITDA that we expect to generate for the twelve months ending December 31, 2012 based on the assumptions and considerations described in the footnotes to the table and (ii) the estimated cash available to pay distributions for the twelve-month period ending December 31, 2012, assuming that the separation and related transactions are consummated on January 1, 2012. We explain each of the adjustments presented below in the footnotes to the table. All of the amounts for the twelve-month period ending December 31, 2012 in the table and footnotes are estimates.

Estimated cash available for distribution

	Twelve months ending December 31, 2012
	(in thousands, except per unit data and ratios)
Estimated Adjusted EBITDA[a]	$ 61,500
Less:	
Cash interest expense[b]	(900)
Maintenance capital expenditures[c]	(9,200)
Expansion capital expenditures[d]	(94,100)
Plus:	
Borrowings and other sources for expansion capital expenditures[e]	94,100
Estimated cash available for distribution	$ 51,400
Expected cash distributions:	
Annualized minimum quarterly distributions per common unit[f]	$ 1.60
Distributions to our common unitholders	$ 41,920
Distributions to our class A unitholder	856
Total distributions to our ownership interests[f]	42,776
Excess of cash available for distribution over minimum annual distributions	8,624
	$ 51,400
Calculation of minimum estimated Adjusted EBITDA necessary to pay minimum annual cash distributions:	
Estimated Adjusted EBITDA	$ 61,500
Less:	
Excess of cash available for distributions over minimum annual distributions	(8,624)
Minimum estimated Adjusted EBITDA necessary to pay minimum annual cash distributions	$ 52,876
Debt covenant ratios:	
Current ratio (as defined)[g]	1.2x
Total Funded Debt/Total Adjusted EBITDA (as defined)[g]	0.0x
Total Adjusted EBITDA/Total Cash Interest Expense (as defined)[g]	68.2x

(a) As reflected in the table below, to generate our Estimated Adjusted EBITDA for the twelve months ending December 31, 2012, we have assumed the following regarding our operations, revenues and expenses:

Gas and oil production key assumptions:		
Net natural gas production volume[(1)]		15.7 Bcf
Average natural gas price on hedged volumes[(2)]	$	5.10 per Mcf
Average natural gas price on unhedged volumes[(2)]	$	4.55 per Mcf
Percentage of net natural gas production assumed to be hedged		47%
Net crude oil production volume[(1)]		114,000 Bbls
Average crude oil price[(2)]	$	79.21 per Bbl
Net natural gas liquids production volume[(1)]		173,000 Bbls
Average natural gas liquids price[(2)]	$	40.55 per Bbl
Partnership management key assumptions:		
Well construction and completion cost mark-up[(3)]		15%-18%
Administration and oversight[(3)]	$	15,000-$250,000 per well
Administration and oversight[(3)]	$	75 per well per month
Gross well services fee range[(3)]		$100-$1,030 per well per month
Statement of operations (in thousands):		
Revenues:		
Gas and oil production[(6)]	$	82,400
Well construction and completion		188,000
Gathering and processing		31,000
Administration and oversight		13,400
Well services		23,100
Total revenues		337,900
Costs and expenses:		
Gas and oil production[(6)]		22,900
Well construction and completion		163,500
Gathering and processing		35,100
Well services		10,900
General and administrative[(5)]		44,000
Depreciation, depletion and amortization		35,000
Total costs and expenses		311,400
Net income[(4)]		26,500
Reconciliation of net income to Estimated Adjusted EBITDA (in thousands):		
Net income	$	26,500
Depreciation, depletion and amortization		35,000
Estimated Adjusted EBITDA	$	61,500

(1) Our forecasted natural gas and oil production volumes, net to our equity interest in the production of our investment partnerships and including our direct interests in producing wells, for the twelve months ending December 31, 2012 assumes that currently producing wells will produce at the rates forecasted in our December 31, 2010 reserve report. Also includes new production from an estimated 227 additional natural gas wells we project to be connected during the twelve months ending December 31, 2012, consisting of (i) 223 wells which we intend to drill on behalf of our investment partnerships and (ii) 4 direct interest wells, both of which we assume will produce at rates consistent with wells of similar characteristics contained in our December 31, 2010 reserve report. Additionally, we have assumed no significant interruptions of production volumes due to mechanical issues such as compressor breakdowns and sales line maintenance. Further, we have assumed no significant logistical issues related to new well hookups, such as delays in pipeline construction, permitting and right-of-ways which we primarily depend on our gathering system service providers to complete.

Of the 227 additional natural gas wells that we project to be connected during the twelve months ending December 31, 2012, only 9 of the wells were recognized as proved, undeveloped locations at December 31, 2010, and such 9 wells had total estimated natural gas and oil reserves of 15.7 Bcfe. At the present time, we have no new information to adjust our reserve estimates for these nine wells and, as such, expect to convert 15.7 Bcfe of estimated natural gas and oil reserves from proved undeveloped reserves to proved developed reserves. These wells are estimated to be connected at various dates throughout 2012, subject to change due to factors including operational issues and weather, and we estimate that these 9 wells will produce an aggregate of 1.4 Bcfe during the twelve months ending December 31, 2012, subject to business plan changes, market factors and operational factors. The remaining 218 natural gas wells that we project to connect during the twelve months ending December 31, 2012 are primarily related to our projected drilling activities in West Virginia and Colorado, which are conducted under farm-out arrangements whereby we do not own the leased acreage, and Tennessee, where we did not previously have any proved undeveloped locations.

The following table outlines historical and projected natural gas and oil production volumes, net to our equity interest in the production of our investment partnerships and including our direct interests in producing wells:

	Natural gas Production (Mcf per day)	Oil Production (Bbl per day)	Natural gas liquids Production (Bbl per day)	Overall Production (Mcfe per day)
Twelve months ended December 31, 2010	35,855	373	499	41,090
Twelve months ended September 30, 2011	33,616	303	465	38,644
Twelve months ending December 31, 2012	42,800	311	472	47,480

The 2.5 mmcfed decrease in overall production from 41.1 mmcfed for the twelve months ended December 31, 2010 to 38.6 mmcfed for the twelve months ended September 30, 2011 was principally due to the lack of wells drilled and connected during the latter part of 2010 and the first half of 2011 due to the cancellation of our fall 2010 partnership management drilling program, which was the result of the acquisition of our assets by Atlas Energy, in November 2010. The 8.9 mmcfed increase in overall production from 38.6 mmcfed for the twelve months ended September 30, 2011 to 47.5 mmcfed for the twelve months ending December 31, 2012 is principally due to the increase wells drilled and connected in 2012 compared with 2011 due to the increase in funds raised from our partnership management drilling programs.

(2) Our weighted average net natural gas sales price of $4.80 per Mcf is calculated by taking into account the fact that we have hedged 7.3 Bcf (or approximately 47% of our forecasted natural gas production volume for the twelve months ending December 31, 2012) at a weighted average natural gas sales price of approximately $5.10 per mcf, and have unhedged production volumes (8.4 Bcf) at an assumed price of $4.55 per Mcf, which is based on the twelve-month NYMEX forward price strip at September 23, 2011 for the twelve months ending December 31, 2012.

We have assumed that all of our crude oil production will be sold at spot market prices. Our average natural gas prices for both hedged and unhedged volumes include a positive basis differential and Btu adjustment of $0.26. The following table indicates historical commodity prices we have received and estimated commodity prices we expect to receive, inclusive of all basis differential and Btu adjustments.

	Overall natural Gas prices per Mcf (inclusive of hedging)	Natural gas prices per Mcf (unhedged portion)	Overall Oil prices per Bbl (inclusive of hedging)	Overall Natural gas liquids prices per Bbl
Twelve months ended December 31, 2010	$7.08	$4.60	$77.31	$37.78
Twelve months ended September 30, 2011	$5.67	$4.54	$88.65	$46.34
Twelve months ending December 31, 2012	$4.80	$4.55	$79.21	$40.55

The overall natural gas price, inclusive of hedging, of $7.08 for the twelve months ended December 31, 2010 is inclusive of hedge prices for contracts that were entered into during periods prior to calendar year 2008, which reflected higher natural gas prices. In connection with the acquisition of our assets by Atlas Energy, in November 2010, all of the natural gas commodity hedges allocated to our 2011 production and future periods were retained by Chevron.

(3) We have assumed that we will raise approximately $250.0 million through investment partnerships in the twelve-month period ending December 31, 2012 and that our equity interest in such partnerships will be approximately 18%. We have assumed that we will drill approximately 175 net wells on behalf of the partnerships, and for each we will receive a 15% to 18% mark-up on the investors' cost to drill and complete the well and a administration and oversight fee that ranges from $15,000 to $250,000 per well. We have assumed that we will, on average, operate approximately 8,500 wells per month on behalf of our partnerships, and receive a gross monthly $75 per well administration fee and a gross monthly well services fee that ranges from $100 to $1,500 per well. We expect that our well services profit margin will be approximately 50%.

(4) We have assumed net income of $26.5 million for the twelve months ending December 31, 2012, as compared to pro forma net loss of $14.3 million for the twelve months ended September 30, 2011. The increase in our net income is due principally to a $50.7 million asset impairment recognized during the twelve months ended September 30, 2011 and anticipated increases in investor funds raised through investment partnerships and the resulting 15% to 18% mark-up on the deployment of such capital to drill and complete the wells as well as an increase in natural gas and oil volumes produced, partially offset by a $28.9 million increase in general and administrative expenses associated with $15.5 million of non-recurring reimbursements received from Chevron for the transition services provided during the twelve months ended September 30, 2011 and estimated increases in compensation and other administrative expenses required to manage our operating activities during the twelve months ending December 31, 2012.

(5) We have forecasted general and administrative expense of $44.0 million for the twelve months ending December 31, 2012, as compared to $15.1 million of pro forma general and administrative for the twelve months ended September 30, 2011. The increase in general and administrative expense is due principally to $15.5 million of non-recurring reimbursements received from Chevron for the transition services provided during the twelve months ended September 30, 2011 and increases in compensation and other administrative costs estimated to manage our operating activities during the twelve months ending December 31, 2012. The pro forma results for the twelve months ended September 30, 2011 included an allocation of historical general and administrative expense for periods prior to February 17, 2011, the date of acquisition of our principal assets and liabilities by Atlas Energy from Old Atlas. Old Atlas was unable to specifically identify general and administrative expense amounts attributable to the Transferred Business because it was not managed as a separate business segment and did not have identifiable labor and other ancillary costs. As such, Old Atlas allocated general and administrative expense to its underlying business segments, including the aggregation of assets and liabilities now defined as the Transferred Business. We have reviewed Old Atlas' general and administrative expense allocation methodology 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.

(6) Gas and oil production revenue includes an $8.9 million reduction for the estimated impact of subordination of our production revenue to investor partners within our investment partnerships for the twelve months ending December 31, 2012. Gas and oil production costs and expenses includes a $2.0

million reduction for the estimated impact of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our investment partnerships for the twelve months ending December 31, 2012.

(b) Our estimated cash interest expense is comprised of the following components:

(i) Approximately $0.2 million attributable to estimated average borrowings of $5.8 million under our proposed new credit facility for the twelve-month period ending December 31, 2012 at an estimated interest rate of 3% to fund a portion of the $94.1 million of estimated expansion capital expenditures. We expect to fund the remaining portion of estimated expansion capital expenditures with a portion of estimated funds received from our investment partnerships for the twelve months ending December 31, 2012 which have not yet been applied to the drilling and completion of wells.

(ii) Approximately $0.7 million of annual commitment fees for the estimated unused portion of our proposed new credit facility for the twelve months ending December 31, 2012.

(c) Our limited partnership agreement requires us to deduct from operating surplus each quarter estimated maintenance capital expenditures as opposed to actual maintenance capital expenditures in order to reduce disparities in operating surplus caused by fluctuations in our actual maintenance capital expenditures. Because of the substantial maintenance capital expenditures we are required to make to maintain the current level of production from our assets, we estimate that our initial annual estimated maintenance capital expenditures for purposes of calculating operating surplus will be approximately $9.2 million per year as described in the next paragraph. The board of directors of our general partner may determine to adjust the annual amount of our estimated maintenance capital expenditures. In years when estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders will be lower than if actual maintenance capital expenditures were deducted from operation surplus.

We estimate that our initial annual estimated maintenance capital expenditures will be approximately $9.2 million per year, consisting of the estimated cost to drill approximately 1.5 Marcellus horizontal direct interest wells to maintain production volumes at a steady level for the twelve months ending December 31, 2012.

(d) Our expansion capital expenditures projected for the twelve months ending December 31, 2012 of approximately $94.1 million are expected to be incurred to drill direct interest and investment partnership wells during such period that are in excess of those required for maintenance capital expenditure purposes described in note (c) above. We expect to fund expansion capital expenditures as described in (e) below.

(e) Reflects funding of the $94.1 million of estimated expansion capital expenditures for the twelve months ending December 31, 2012 with $5.8 million of estimated average borrowings under our proposed new credit facility and a portion of estimated funds received from our investment partnerships for the twelve months ending December 31, 2012 which have not yet been applied to the drilling and completion of wells. In the future, we anticipate that we will continue to utilize these sources of financing to fund expansion and investment capital expenditures. As a result, we do not expect any such capital expenditures to have an immediate impact on available cash for distribution.

(f) The table below sets forth the assumed number of outstanding common units and class A units upon the closing of the separation and related transactions and the full minimum quarterly distribution payable on the outstanding common units and class A units for the twelve-month period ending December 31, 2012.

	Number of units	Estimated distribution per unit	Estimated annual distributions
Common units	26,200,000	$1.60	$41,920,000
Class A units	534,694[(1)]	$1.60	855,512
Total	26,734,694		$42,775,512

(1) The class A units will be entitled to 2% of all quarterly distributions that we make. The 534,694 class A units reflect the general partner's implied 2% ownership interest in our outstanding ownership interests, which will increase if we issue additional equity securities in the future.

(g) We have assumed that our proposed new credit facility will contain financial covenants identical to those contained in Atlas Energy's current credit facility, which would require us to maintain, as of the end of each fiscal quarter, a current ratio (as defined in the Atlas Energy credit facility) of not less than 1.0 to 1.0; a ratio of funded debt to Adjusted EBITDA (as defined in the Atlas Energy credit facility) measured for the preceding twelve months of not more than 3.75 to 1.0; and a ratio of Adjusted EBITDA to cash interest expense (as defined in the Atlas Energy credit facility) measured for the preceding twelve months of not less than 2.5 to 1.0. We would have been in compliance on a pro forma basis with these covenants for the twelve months ended December 31, 2010 and September 30, 2011 and believe we will be in compliance with these covenants for the twelve months ending December 31, 2012. In addition, we anticipate that a default by us on the payment of any indebtedness in excess of $15.0 million will constitute an event of default under our credit agreement that would prohibit us from making distributions. We expect that our proposed new credit facility will permit us to make distributions to our unitholders as long as we are neither in default nor, following such distribution, would be in default. See "Credit Agreement" beginning on page 219.

In preparing the estimates above, we have assumed that there will be no material change in the following matters, and thus they will have no impact on our estimated Adjusted EBITDA:

- There will not be any material expenditures related to new federal, state or local regulations in the areas where we operate.
- There will not be any material change in the natural gas industry or in market, regulatory and general economic conditions that would affect our cash flow.
- We will not undertake any extraordinary transactions that would materially affect our cash flow.
- There will be no material nonperformance or credit-related defaults by suppliers, customers or vendors.

While we believe that the assumptions we used in preparing the estimates set forth above are reasonable based upon management's current expectations concerning future events, they are inherently uncertain and are subject to significant business, economic, regulatory and competitive risks and uncertainties, including those described in "Risk Factors" beginning on page 28 that could cause actual results to differ materially from those we anticipate. If our assumptions are not realized, the actual available cash that we generate could be substantially less than the amount we currently estimate and could, therefore, be insufficient to permit us to pay the full minimum quarterly distribution or any amount on all our outstanding units with respect to the four calendar quarters ending December 31, 2012 or thereafter, in which event the market price of the common units may decline materially.

Sensitivity Analysis

Our ability to generate sufficient cash from our operations to pay distributions to our unitholders of not less than the minimum quarterly distribution per unit for the twelve months ending December 31, 2012 is a function of the following primary variables:

- the amount of natural gas and oil we produce;
- the price at which we sell our natural gas and oil; and
- the amount of funds raised from our investment partnerships.

In the paragraphs below, we discuss the impact that changes in these variables, holding all other variables constant, would have on our ability to generate sufficient cash from our operations to pay the minimum quarterly distribution on our outstanding units. This sensitivity analysis also assumes that we will be able to identify suitable drilling locations for the number of wells forecasted to be drilled based on the amount of funds raised from our investment partnerships and that we are able to drill that number of wells during the forecast period.

Production volume changes. For purposes of our estimates set forth above, we have assumed that our net production will total 17.4 Bcfe during the twelve months ending December 31, 2012. If our actual net production realized during such twelve-month period is 10% more (or 10% less) than such estimate (that is, if actual net realized production is 19.1 Bcfe or 15.7 Bcfe), we estimate that our estimated cash available to pay distributions would change by approximately $6.0 million.

Commodity price changes. For purposes of our estimates set forth above, we have assumed that our weighted average net realized commodity price for our net production volumes is $4.80 per Mcf for natural gas, $79.21 per barrel for crude oil and $40.55 per barrel for natural gas liquids. If the average realized commodity price for our net production volumes that are unhedged were to change by 10%, we estimate that our estimated cash available to pay distributions would change by approximately $4.4 million, assuming no changes in any other variables and inclusive of our commodity derivative contracts.

Funds raised changes. For purposes of our estimates set forth above, we have assumed funds raised from our investment partnerships will total $250.0 million during the twelve months ending December 31, 2012. If actual funds raised during such period are 10% more or less than our estimate, we estimate that our estimated cash available would change by approximately $2.8 million.

Unaudited Pro Forma Available Cash for Distribution

If we had completed the transactions contemplated in this information statement on January 1, 2010, our pro forma available cash for distribution would have been $52.3 million for the twelve months ended December 31, 2010. This amount would have been sufficient to pay the minimum quarterly distribution rate of $0.40 per unit ($1.60 on an annual basis) on our outstanding common units and class A units.

If we had completed the transactions contemplated in this information statement on October 1, 2010, our pro forma available cash for distribution would have been $42.3 million for the twelve months ended September 30, 2011. This amount would have been insufficient by approximately $0.5 million to pay the minimum quarterly distribution rate of $0.40 per unit ($1.60 on an annual basis) on our outstanding common units and class A units.

Pro forma cash available for distributions excludes any cash from working capital or other borrowings. We may also use cash from these sources for distributions. Pursuant to the terms of our partnership agreement, our general partner would have had the discretionary authority to cause us to borrow funds under our proposed new credit facility, or from other sources, to make up some or all of this estimated shortfall.

The following table illustrates, on a pro forma basis for the twelve months ended December 31, 2010 and September 30, 2011, cash available to pay distributions, assuming that the separation and distribution and the related transactions had been consummated on January 1, 2010 and October 1, 2010, respectively.

The pro forma financial statements, from which pro forma available cash is derived, do not purport to present our results of operations had the transactions contemplated above actually been completed as of the dates indicated. Furthermore, available cash is a cash accounting concept, while our pro forma financial statements have been prepared on an accrual basis. We derived the amounts of pro forma available cash stated above in the manner described in the table below. As a result, the amount of pro forma available cash should only be viewed as a general indication of the amount of available cash that we might have generated had we been formed and completed the transactions contemplated below in earlier periods.

Our unaudited pro forma combined financial statements, which are included elsewhere in this information statement and provide the basis from which pro forma available cash is derived, reflect the historical combined financial statements of Atlas Energy E&P Operations (the "Predecessor"), included elsewhere in this information statement, and were adjusted on a pro forma basis to give effect to the separation and related transactions. Atlas Energy acquired the Predecessor's principal assets and liabilities (the "Transferred Business") on

February 17, 2011 from Atlas Energy, Inc. ("Old Atlas"), the former owner of Atlas Energy's general partner. 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 which required, among other items, for Atlas Energy to retrospectively adjust its prior year financial statements to reflect the Transferred Business' results of operations for periods prior to the date of acquisition. The Transferred Business' historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by Old Atlas to the underlying business segments, including the aggregation of assets and liabilities now defined as the Predecessor. We have reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas 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.

	Pro forma	
	Twelve months ended December 31, 2010	**Twelve months ended September 30, 2011**
	(in thousands, except per unit data and ratios)	
Net income (loss)[(a)]	$ 8,831	$ (14,250)
Plus:		
Interest expense	450	450
Depreciation, depletion and amortization	40,758	32,848
Asset impairment	50,669	50,669
Less:		
Estimated incremental general and administrative expense[(b)]	(32,619)	(14,155)
Adjusted EBITDA[(c)]	$ 68,089	$ 55,562
Less:		
Cash interest expense[(d)]	(50)	(50)
Estimated maintenance capital expenditures[(e)]	(15,744)	(13,236)
Cash available for distribution	$ 52,295	$ 42,276
Expected cash distributions[(f)]:		
Annualized minimum quarterly distribution per common unit	$ 1.60	$ 1.60
Distributions to our common unitholders	$ 41,920	$ 41,920
Distributions to our Class A units	856	856
Total distributions to our ownership interests	$ 42,776	$ 42,776
Excess/(shortfall)	$ 9,519	$ (500)
Debt covenant ratios:		
Current ratio (as defined)[(g)]	1.1x	2.0x
Total Funded Debt/Total Adjusted EBITDA (as defined)[(g)]	0.0x	0.1x
Total Adjusted EBITDA/Total Cash Interest Expense (as defined)[(g)]	1,361.8x	1,111.2x

(a) The following table reconciles pro forma net income for the twelve months ended September 30, 2011:

Pro forma net income for the year ended December 31, 2010	$ 8,831
Plus: Pro forma net income for the nine months ended September 30, 2011	24,369
Less: Pro forma net income for the nine months ended September 30, 2010	(47,450)
Pro forma net loss for the twelve months ended September 30, 2011	$(14,250)

(b) Pro forma net income for the twelve months ended September 30, 2011 includes an allocation of historical general and administrative expense for periods prior to February 17, 2011, the date of acquisition of our principal assets and liabilities by Atlas Energy from Old Atlas. Old Atlas was unable to specifically identify general and administrative expense amounts attributable to the Transferred Business because it was not managed as a separate business segment and did not have identifiable labor and other ancillary costs. As such, Old Atlas allocated general and administrative expense to its underlying business segments, including the aggregation of assets and liabilities now defined as the Transferred Business. We have reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas 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 to the date of acquisition, pro forma net income reflects general and administrative expense associated with our operations. The adjustments reflect incremental general and administrative expense we estimate we would have incurred for periods prior to February 17, 2011, the date of acquisition, based upon the current general and administrative expense level experienced by our operations.

(c) EBITDA represents net income before net interest expense, income taxes, and depreciation, depletion and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances to directors and employees. EBITDA and Adjusted EBITDA are not measures of performance calculated in accordance with GAAP. Although not prescribed under GAAP, we believe the presentation of EBITDA and Adjusted EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other entities that have different financing and capital structures or tax rates. EBITDA and Adjusted EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity.

(d) Reflects an increase from historical interest expense, excluding amortization of deferred financing costs, as a result of interest expense principally related to average borrowings under Atlas Energy's credit facility.

(e) Historically, our Predecessor did not make a distinction between maintenance and expansion and investment capital expenditures. For purposes of the presentation of pro forma cash available for distribution, we have estimated our Predecessor's maintenance capital expenditures for the respective periods presented based upon our natural gas and oil reserve replacement cost and the levels of production experienced for the respective periods presented.

(f) The table below sets forth the assumed number of outstanding common units and general partner ownership interest upon the closing of the distribution and the full minimum quarterly distribution payable on them for the twelve-month period ending December 31, 2012:

	Number of units	Estimated Distribution per unit	Estimated annual distributions
Common units	26,200,000	$1.60	$41,920,000
Class A units	534,694(1)	$1.60	855,512
Total	26,734,694		$42,775,512

(1) The class A units will be entitled to 2% of all quarterly distributions that we make. The 534,694 class A units reflect the general partner's implied 2% ownership interest in our outstanding ownership interests, which will increase if we issue additional equity securities in the future.

(g) We have assumed that our proposed new credit facility will contain financial covenants identical to those contained in Atlas Energy's current credit facility, which would require us to maintain, as of the end of each fiscal quarter, a current ratio (as defined in the Atlas Energy credit facility) of not less than 1.0 to 1.0; a ratio of funded debt to Adjusted EBITDA (as defined in the Atlas Energy credit facility) measured for the preceding twelve months of not more than 3.75 to 1.0; and a ratio of Adjusted EBITDA to cash interest expense (as defined in the Atlas Energy credit facility) measured for the preceding twelve months of not less than 2.5 to 1.0. We would have been in compliance on a pro forma basis with these covenants for the twelve months ended December 31, 2010 and September 30, 2011 and we believe we will be in compliance with these covenants for the twelve months ending December 31, 2012. In addition, we anticipate that a default by us on the payment of any indebtedness in excess of $15.0 million will constitute an event of default under our credit agreement that would prohibit us from making distributions. We expect that our proposed new credit facility will permit us to make distributions to our unitholders as long as we are neither in default nor, following such distribution, would be in default. See "Credit Agreement" beginning on page 219.

CAPITALIZATION

The following table, which should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 99, "Atlas Resource Partners, L.P. Unaudited Pro Forma Condensed Combined Financial Statements" beginning on page F-2, and the financial statements and accompanying notes included elsewhere in this information statement, sets forth our cash and cash equivalents and combined capitalization as of September 30, 2011 on an historical basis and on a pro forma basis after giving effect to the formation of Atlas Resource Partners and a contribution to Atlas Resource Partners of all the assets and liabilities of the natural gas and oil production and development business and partnership management business, along with the related issuance of 26,200,000 common units of Atlas Resource Partners to Atlas Energy.

	As of September 30, 2011	
	Historical	**Pro forma**
	(in thousands)	
Cash and cash equivalents	$ 59,986	$ 59,986
Credit facility	—	2,000
Total debt	—	2,000
Equity	455,916	—
General partner's interest	—	9,118
Common limited partners' interest	—	446,798
Accumulated other comprehensive income	13,460	13,460
Total equity/partners' capital	469,376	469,376
Total capitalization	$469,376	$471,376

SELECTED HISTORICAL CONDENSED COMBINED 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 has transferred, or will transfer, to us prior to the distribution. The condensed combined statement of operations data for the nine months ended September 30, 2011 and 2010 and the condensed combined balance sheet data as of September 30, 2011 have been derived from Atlas Energy E&P Operations' unaudited interim condensed combined financial statements included elsewhere in this information statement. The condensed combined statement of operations data for the years ended December 31, 2010, 2009 and 2008 and the condensed combined balance sheet data as of December 31, 2010 and 2009 are derived from Atlas Energy E&P Operations' audited combined financial statements included elsewhere in this information statement. The condensed combined statement of operations data for the years ended December 31, 2007 and 2006 and the condensed combined balance sheet data as of December 31, 2007 and 2006 are derived from Atlas Energy E&P Operations' unaudited combined financial statements that are not included in this information statement. The unaudited combined financial statements have been prepared on the same basis as the audited combined financial statements and, in the opinion of our management, include all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the information set forth herein.

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 beginning on page F-12, unaudited condensed combined financial statements and accompanying notes beginning on page F-39 and "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 99. 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. For more information regarding these anticipated changes, see "Atlas Resource Partners, L.P. Unaudited Pro Forma Condensed Combined Financial Statements" beginning on page F-2.

	Nine Months Ended September 30,		Years Ended December 31,				
	2011	2010 (Restated)	2010 (Restated)	2009 (Restated)	2008 (Restated)	2007 (Restated)	2006 (Restated)
			(in thousands, except per unit data)				
Statement of operations data:							
Revenues:							
Gas and oil production	$ 51,654	$ 70,816	$ 93,050	$112,979	$127,083	$ 99,015	$ 88,449
Well construction and completion	64,336	176,685	206,802	372,045	415,036	321,471	198,567
Gathering and processing	14,048	11,414	14,087	18,839	19,098	13,781	9,074
Administration and oversight	5,073	7,473	9,716	15,554	19,277	17,955	11,762
Well services	15,051	15,589	20,994	17,859	18,513	16,663	12,953
Total revenues	150,162	281,977	344,649	537,276	599,007	468,885	320,805
Costs and expenses:							
Gas and oil production	11,953	16,863	23,323	25,557	25,104	17,638	13,881
Well construction and completion	54,754	149,724	175,247	315,546	359,609	279,540	172,666
Gathering and processing	16,377	16,499	20,221	25,269	19,098	13,781	29,545
Well services	6,077	7,691	10,822	9,330	10,654	9,062	7,337
General and administrative	12,275	8,536	11,381	15,832	13,074	9,864	24,124
Depreciation, depletion and amortization	24,019	31,929	40,758	43,712	39,781	28,388	22,491
Asset impairment	—	—	50,669	156,359	—	—	—
Total costs and expenses	125,455	231,242	332,421	591,605	467,320	358,273	270,044
Operating income (loss)	$ 24,707	$ 50,735	$ 12,228	$ (54,329)	$131,687	$110,612	$ 50,761
Loss on asset sales	—	(2,947)	(2,947)	—	—	—	—
Net income (loss)	$ 24,707	$ 47,788	$ 9,281	$ (54,329)	$131,687	$110,612	$ 50,761

	Nine Months Ended September 30,		Years Ended December 31,				
	2011	2010 (Restated)	2010 (Restated)	2009 (Restated)	2008 (Restated)	2007 (Restated)	2006 (Restated)
			(in thousands, except per unit data)				
Other financial data:							
Adjusted EBITDA[1]	$ 48,726	$ 79,717	$100,708	$145,742	$ 171,468	$ 139,000	$ 73,252
Balance sheet data (at period end):							
Property, plant and equipment, net	$526,634	$535,297	$508,484	$503,386	$ 616,257	$ 417,332	$284,830
Total assets	669,296	717,265	649,232	690,603	834,260	520,003	407,366
Total debt, including current portion	—	—	—	—	—	—	—
Total equity	469,376	377,223	381,882	351,586	515,622	262,170	214,980
Cash flow data:							
Net cash provided by operating activities	$ 41,614	$100,096	$ 60,586	$192,201	$ 169,278	$ 201,922	$ 88,540
Net cash used in investing activities	(36,270)	(70,506)	(92,423)	(98,393)	(262,153)	(156,442)	(83,320)
Net cash provided by (used in) financing activities	54,642	(29,590)	31,837	(93,808)	92,875	(45,480)	(5,220)
Capital expenditures	(36,270)	(70,716)	(93,608)	(99,302)	(264,125)	(158,456)	(83,320)
Operating data[2]:							
Net production:							
Natural gas (mcfd)	31,687	36,610	35,855	38,644	32,791	27,156	24,511
Oil (bpd)	296	391	373	427	423	418	413
Natural gas liquids (bpd)	449	493	499	101	—	—	—
Total (mcfed)	36,158	41,914	41,090	41,814	35,327	29,664	26,989
Average sales price:							
Natural gas (per Mcf)[3]:							
Realized price, after hedge	$ 5.24	$ 7.15	$ 7.08	$ 7.54	$ 9.40	$ 8.91	$ 8.83
Realized price, before hedge	$ 4.69	$ 4.74	$ 4.60	$ 4.04	$ 9.63	$ 7.71	$ 7.90
Oil (per Bbl):							
Realized price, after hedge	$ 90.65	$ 75.66	$ 77.31	$ 71.34	$ 92.28	$ 70.11	$ 62.30
Realized price, before hedge	$ 89.79	$ 69.07	$ 71.34	$ 57.41	$ 91.71	$ 70.11	$ 62.30
Natural gas liquids realized price (per Bbl)	$ 48.43	$ 36.67	$ 37.78	$ 36.19	$ —	$ —	$ —
Production costs (per Mcfe):							
Lease operating expenses[4]	$ 1.01	$ 1.27	$ 1.27	$ 1.10	$ 1.06	$ 0.86	$ 0.83
Production taxes	0.05	0.03	0.04	0.03	0.03	0.03	0.03
Transportation and compression	0.48	0.58	0.65	0.68	0.85	0.74	0.55
Total	$ 1.55	$ 1.89	$ 1.96	$ 1.80	$ 1.94	$ 1.63	$ 1.41

(1) We define Adjusted EBITDA as earnings before interest, taxes, depreciation, depletion and amortization, plus certain non-cash items such as compensation expenses associated with unit issuances to directors and employees of our general partner. Adjusted EBITDA is not a measure of performance calculated in accordance with GAAP. Although not prescribed under GAAP, we believe the presentation of Adjusted EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other companies that have different financing and capital structures or tax rates. Adjusted EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. Adjusted EBITDA, as we calculate it, may not be comparable to Adjusted EBITDA measures reported by other companies. Adjusted EBITDA is also a financial measurement that, with certain negotiated adjustments, will be utilized within our proposed new credit facility. In addition, Adjusted EBITDA does not represent funds available for discretionary use or the payment of distributions. The following reconciles our net income to Adjusted EBITDA for the periods indicated:

	Nine Months Ended September 30,		Years Ended December 31,				
	2011	2010 (Restated)	2010 (Restated)	2009 (Restated)	2008 (Restated)	2007 (Restated)	2006 (Restated)
					(in thousands)		
Net income (loss)	$24,707	$47,788	$ 9,281	$ (54,329)	$131,687	$110,612	$50,761
Depreciation, depletion and amortization	24,019	31,929	40,758	43,712	39,781	28,388	22,491
Asset impairment	—	—	50,669	156,359	—	—	—
Adjusted EBITDA	$48,726	$79,717	$100,708	$145,742	$171,468	$139,000	$73,252

(2) "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.

(3) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010 and 2009. Including the effect of this subordination, the average realized gas sales price were $4.44 per Mcf ($3.89 per Mcf before the effects of financial hedging) and $5.78 per Mcf ($3.47 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business—Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

(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. Including the effects of these costs, total lease operating expenses per Mcfe were $0.67 per Mcfe ($1.21 per Mcfe for total production costs) and $0.86 per Mcfe ($1.47 per Mcfe for total production costs for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business—Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The historical financial statements included in this information statement reflect substantially all the assets, liabilities and operations of various wholly owned subsidiaries of Atlas Energy to be contributed to us prior to the distribution. We refer to these subsidiaries' assets, liabilities and operations as Atlas Energy E&P Operations or our predecessor. The discussion and analysis presented below refer to and should be read in conjunction with the audited combined financial statements and related notes, the unaudited interim condensed combined financial statements and related notes and the unaudited pro forma condensed combined financial statements, each included elsewhere in this information statement. The following discussion may contain forward-looking statements that reflect our plans, estimates and beliefs. The words "believe," "expect," "anticipate," "project," and similar expressions, among others, generally identify "forward-looking statements," which speak only as of the date the statements were made. The matters discussed in these forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from those made, projected or implied in the forward-looking statements. Factors that could cause or contribute to these differences include those discussed below and elsewhere in this information statement, particularly in "Risk Factors" and "Forward-Looking Statements" beginning on pages 28 and 59, respectively. We believe the assumptions underlying the combined financial statements are reasonable. However, our predecessor's combined financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows in the future or what they would have been had our predecessor been a separate, stand-alone company during the periods presented.

As explained above, except as otherwise indicated or unless the context otherwise requires, the information included in this discussion and analysis assumes the completion of all the transactions referred to in this information statement in connection with the separation and distribution. Unless the context otherwise requires, references in this information statement to "Atlas Resource Partners, L.P.," "Atlas Resource Partners," "the partnership," "we," "us," "our" and "our company", when used in a historical context or in the present tense, refer to the subsidiaries that Atlas Energy will contribute to Atlas Resource Partners in connection with the completion of all of the transactions referred to in this information statement in connection with the separation and distribution and, when used prospectively, refer to Atlas Resource Partners, L.P., a Delaware limited partnership, and its combined subsidiaries. References in this information statement to "Atlas Energy" or "Atlas Energy, L.P." refers to Atlas Energy, L.P., a Delaware limited partnership, and its consolidated subsidiaries, unless the context otherwise requires. References in this information statement to "our general partner" refer to Atlas Resource Partners GP, LLC, a Delaware limited liability company, the general partner of Atlas Resource Partners and a wholly owned subsidiary of Atlas Energy.

Introduction

Management's discussion and analysis, which we refer to in this information statement as "MD&A," of our results of operations and financial condition is provided as a supplement to the audited financial statements and unaudited interim financial statements and footnotes thereto included elsewhere herein to help provide an understanding of our financial condition, changes in financial condition and results of our operations.

MD&A is organized as follows:

- *Separation from Atlas Energy*—This section provides an overview of the decision to separate Atlas Resource Partners from Atlas Energy and of the conditions and costs of the separation.
- *Overview*—This section provides a general description of our business.
- *Financial Presentation*—This section describes the major principles used to prepare the financial statements, including the allocation methodology and adjustments made to present our combined financial statements
- *Combined Results of Operations*—This section provides an analysis of our results of operations for the nine months ended September 30, 2011 and 2010, and for the fiscal years ended December 31, 2010, 2009 and 2008.

- *Liquidity and Capital Resources*—This section provides a discussion of our financial condition and cash flows for the nine months ended September 30, 2011 and 2010, and for the fiscal years ended December 31, 2010, 2009 and 2008. It also includes a discussion of how the separation will affect our capital resources.
- *Critical Accounting Policies and Estimates*—This section describes the accounting policies and estimates that we consider most important for our business and that require significant judgment.
- *Quantitative and Qualitative Disclosures About Market Risk*—This section describes our potential exposure to the risk of loss arising from adverse changes in natural gas and oil prices.

Separation from Atlas Energy

On October 17, 2011, Atlas Energy announced that it intended to separate its existing natural gas and oil assets and its partnership management business from the remainder of its businesses. The separation would occur through Atlas Energy's contribution of its existing natural gas and oil development and production assets and its partnership management business to Atlas Resource Partners, L.P., a newly formed subsidiary, and through the distribution of approximately 5.24 million common units representing an approximately 19.6% limited partner interest in Atlas Resource Partners to Atlas Energy unitholders. Atlas Resource Partners, L.P. was formed in Delaware in October 2011 for the purpose of holding such businesses and is currently a wholly owned subsidiary of Atlas Energy.

On October 7, 2011, the board of directors of Atlas Energy's general partner conditionally approved the distribution of approximately 5.24 million of our outstanding common units on a pro rata basis. On February 15, 2012, the board of directors of Atlas Energy's general partner approved the distribution. Following the distribution, Atlas Energy will own approximately 20.96 million common units representing an approximately 78.4% limited partner interest in us. In addition, it will own 100% of the equity of our general partner, Atlas Resource Partners GP, LLC, which, in turn, will own 534,694 class A units representing a 2% general partner interest in us, as well as all of our incentive distribution rights. The distribution is subject to a number of conditions. We cannot assure you that any or all of these conditions will be met. For a complete discussion of all of the conditions to the distribution, see "The Separation and Distribution—Conditions to the Distribution" beginning on page 65.

In connection with the separation, 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 proposed 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 flow 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.

Overview

We are a limited partnership formed in October 2011 to own and operate substantially all of the natural gas and oil development and production assets and the partnership management business of Atlas Energy. On February 17, 2011, Atlas Energy acquired these and other assets (the "Transferred Business") from Atlas Energy, Inc. ("Old Atlas"), the former owner of Atlas Energy's general partner. The assets acquired included, among other assets, the following:

- Old Atlas's partnership management business, which sponsors tax-advantaged direct investment natural gas and oil partnerships, which funds a portion of our natural gas and oil well drilling; and
- 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.

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 our combined financial statements, Atlas Energy's net investment in us is shown as equity in the combined financial statements. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the 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 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 on February 17, 2011 constituted a transaction between entities under common control. 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 Atlas Energy's consolidated 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 Atlas Energy's consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, Atlas Energy reflected the impact of the acquisition of the Transferred Business on its consolidated combined financial statements, from which our combined financial statements were derived, 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 its historical consolidated 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 historical consolidated combined statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners. The Transferred Business' historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by Old Atlas to the underlying business segments, including the aggregation of assets and liabilities now defined as the Predecessor. We have reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas 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.

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

Results of Operations

Gas and Oil Production

Production Profile. Currently, our natural gas and oil production operations are focused in various shale plays in the northeastern and midwestern United States. As part of Atlas Energy's agreement with Old Atlas to acquire the Atlas Energy E&P Operations, 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 September 30, 2011, we have established production positions in the following areas:

- the Appalachian Basin, including in the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas;
- 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;
- the Antrim Shale in Michigan, where we produce out of the biogenic region of the shale similar to the New Albany Shale; and
- the Chattanooga Shale in northeastern Tennessee.

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 nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010, 2009 and 2008:

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Gross wells drilled:					
Appalachia	12	19	22	174	821
New Albany/Antrim	—	57	66	93	5
Niobrara	50	6	29	—	—
	62	82	117	267	826
Our share of gross wells drilled(1):					
Appalachia	3	4	6	45	272
New Albany/Antrim	—	16	19	23	2
Niobrara	11	2	9	—	—
	14	22	34	68	274
Gross wells turned in line:					
Appalachia	1	77	83	307	943
New Albany/Antrim	13	68	76	65	—
Niobrara	37	—	8	—	—
	51	145	167	372	943

(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.

Production Volumes. The following table presents our total net natural gas, oil and natural gas liquids production volumes and production per day during the nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010, 2009 and 2008:

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Production:(1)(2)					
Appalachia:(3)					
Natural gas (MMcf)	7,689	9,554	12,363	13,905	12,002
Oil (000s Bbls)	81	107	136	156	155
Natural gas liquids (000s Bbls)	122	134	182	37	—
Total (MMcfe)	8,910	11,002	14,274	15,062	12,930
New Albany/Antrim:					
Natural gas (MMcf)	866	441	724	200	—
Oil (000s Bbls)	—	—	—	—	—
Natural gas liquids (000s Bbls)	—	—	—	—	—
Total (MMcfe)	866	441	724	200	—
Niobrara:					
Natural gas (MMcf)	95	—	—	—	—
Oil (000s Bbls)	—	—	—	—	—
Natural gas liquids (000s Bbls)	—	—	—	—	—
Total (MMcfe)	95	—	—	—	—
Total:					
Natural gas (MMcf)	8,651	9,994	13,087	14,105	12,002
Oil (000s Bbls)	81	107	136	156	155
Natural gas liquids (000s Bbls)	122	134	182	37	—

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Total (MMcfe)	9,871	11,442	14,998	15,262	12,930
Production per day:(1)(2)					
Appalachia:(3)					
Natural gas (Mcfd)	28,166	34,995	33,872	38,096	32,791
Oil (Bpd)	296	391	373	427	423
Natural gas liquids (Bpd)	449	493	499	101	—
Total (Mcfed)	32,637	40,299	39,107	41,267	35,327
New Albany/Antrim:					
Natural gas (Mcfd)	3,172	1,614	1,983	548	—
Oil (Bpd)	—	—	—	—	—
Natural gas liquids (Bpd)	—	—	—	—	—
Total (Mcfed)	3,172	1,614	1,983	548	—
Niobrara:					
Natural gas (Mcfd)	349	—	—	—	—
Oil (Bpd)	—	—	—	—	—
Natural gas liquids (Bpd)	—	—	—	—	—
Total (Mcfed)	349	—	—	—	—
Total:					
Natural gas (Mcfd)	31,687	36,610	35,855	38,644	32,791
Oil (Bpd)	296	391	373	427	423
Natural gas liquids (Bpd)	449	493	499	101	—
Total (Mcfed)	36,158	41,914	41,090	41,814	35,327

(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.
(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, 2010. The following table presents our production revenues and average sales prices for our natural gas, oil and natural gas liquids production for the nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010, 2009 and 2008, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Production revenues (in thousands):					
Appalachia:(1)					
Natural gas revenue	$33,888	$55,260	$71,726	$ 99,024	$112,809
Oil revenue	7,341	8,080	10,541	11,119	14,274
Natural gas liquids revenue	5,930	4,935	6,879	1,334	—
Total revenues	$47,159	$68,275	$89,146	$111,477	$127,083

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
New Albany/Antrim:					
Natural gas revenue	$ 4,041	$ 2,541	$ 3,904	$ 1,502	$ —
Oil revenue	—	—	—	—	—
Natural gas liquids revenue	—	—	—	—	—
Total revenues	$ 4,041	$ 2,541	$ 3,904	$ 1,502	$ —
Niobrara:					
Natural gas revenue	$ 454	$ —	$ —	$ —	$ —
Oil revenue	—	—	—	—	—
Natural gas liquids revenue	—	—	—	—	—
Total revenues	$ 454	$ —	$ —	$ —	$ —
Total:					
Natural gas revenue	$38,383	$57,801	$75,630	$100,526	$112,809
Oil revenue	7,341	8,080	10,541	11,119	14,274
Natural gas liquids revenue	5,930	4,935	6,879	1,334	—
Total revenues	$51,654	$70,816	$93,050	$112,979	$127,083
Average sales price:[2]					
Natural gas (per Mcf):					
Total realized price, after hedge[3]	$ 5.24	$ 7.15	$ 7.08	$ 7.54	$ 9.40
Total realized price, before hedge[3]	$ 4.69	$ 4.74	$ 4.60	$ 4.04	$ 9.63
Oil (per Bbl):					
Total realized price, after hedge	$ 90.65	$ 75.66	$ 77.31	$ 71.34	$ 92.28
Total realized price, before hedge	$ 89.79	$ 69.07	$ 71.34	$ 57.41	$ 91.71
Natural gas liquids (per Bbl) total realized price	$ 48.43	$ 36.67	$ 37.78	$ 36.19	$ —
Production costs (per Mcfe):[2]					
Appalachia:[1]					
Lease operating expenses[4]	$ 1.00	$ 1.25	$ 1.25	$ 1.08	$ 1.06
Production taxes	0.05	0.03	0.03	0.03	0.03
Transportation and compression	0.53	0.60	0.68	0.68	0.85
	$ 1.57	$ 1.89	$ 1.97	$ 1.79	$ 1.94
New Albany/Antrim:					
Lease operating expenses	$ 1.19	$ 1.63	$ 1.59	$ 2.54	$ —
Production taxes	0.12	0.11	0.10	0.05	—
Transportation and compression	0.03	0.10	0.09	0.09	—
	$ 1.35	$ 1.84	$ 1.77	$ 2.67	$ —
Niobrara:					
Lease operating expenses[4]	$ 1.02	$ —	$ —	$ —	$ —
Production taxes	0.02	—	—	—	—
Transportation and compression	0.46	—	—	—	—
	$ 1.50	$ —	$ —	$ —	$ —
Total:					
Lease operating expenses[4]	$ 1.01	$ 1.27	$ 1.27	$ 1.10	$ 1.06
Production taxes	0.05	0.03	0.04	0.03	0.03
Transportation and compression	0.48	0.58	0.65	0.68	0.85
	$ 1.55	$ 1.89	$ 1.96	$ 1.80	$ 1.94

(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 nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010 and 2009. Including the effect of this subordination, the average realized gas sales price were $4.44 per Mcf ($3.89 per Mcf before the effects of financial hedging) and $5.78 per Mcf ($3.47 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business —Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

(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. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.62 per Mcfe ($1.19 per Mcfe for total production costs) and $0.83 per Mcfe ($1.46 per Mcfe for total production costs) for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $0.67 per Mcfe ($1.21 per Mcfe for total production costs) and $0.86 per Mcfe ($1.47 per Mcfe for total production costs for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business —Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

Nine Months Ended September 30, 2011 Compared with the Nine Months Ended September 30, 2010. Total natural gas revenues were $38.4 million for the nine months ended September 30, 2011, a decrease of $19.4 million from $57.8 million for the nine months ended September 30, 2010. This decrease consisted of a $19.1 million decrease attributable to lower realized natural gas prices and a $7.0 million decrease attributable to lower production volumes, partially offset by a $6.7 million decrease in gas revenues allocated to the investor partners within our investment partnerships for the nine months ended September 30, 2011 compared with the prior year period. Total oil and natural gas liquids revenues were $13.3 million for the nine months ended September 30, 2011, an increase of $0.3 million from $13.0 million for the comparable prior year period. This increase resulted primarily from a $1.0 million increase from the sale of natural gas liquids and a $1.6 million increase associated with higher average oil and natural gas liquids realized prices, partially offset by a $2.3 million decrease associated with lower oil production volumes. The decrease in natural gas, oil and natural gas liquids 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 Atlas Energy's announcement of the acquisition of the Transferred Business in November 2010. The decrease in gas revenues allocated to the investor partners within our investment partnerships was related to the overall decrease in natural gas revenue.

Appalachia production costs were $10.7 million for the nine months ended September 30, 2011, a decrease of $5.3 million from $16.0 million for the nine months ended September 30, 2010. This decrease was principally due to a $2.2 million decrease associated with water hauling and disposal costs, a $1.8 million decrease in transportation costs, a $0.8 million decrease for labor-related costs and a $1.9 million decrease associated with maintenance expenses and other costs associated with our natural gas and oil operations, partially offset by a $1.4 million decrease associated with our proportionate share of lease operating expenses associated with our revenue that was allocated to the investor partners within our investment partnerships. The decreases in water hauling and disposal costs, transportation costs, maintenance expenses and other costs were primarily due to a decrease in natural gas volumes between the periods. New Albany/Antrim production costs were $1.2 million for the nine months ended September 30, 2011, an increase of $0.4 million from $0.8 million for the comparable prior year period. This increase was primarily attributable to a $0.1 million increase for labor-related expense and a $0.3 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 allocated 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 cancellations of our fall 2010 drilling program, which was the result of Atlas Energy's announcement of the acquisition of the Transferred Business in November 2010. The increase in gas revenues allocated to the investor partners within our investment partnerships was primarily the result of an increase in our natural gas revenues that qualified for allocation 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 allocated 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. Michigan/Indiana 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 increases in labor, maintenance and compression station expenses associated with the growth of our operations.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008. Total natural gas revenues were $100.5 million for the year ended December 31, 2009, a decrease of $12.3 million from $112.8 million for the year ended December 31, 2008. This decrease consisted of a $22.3 million decrease attributable to lower realized natural gas prices and $5.9 million of gas revenues subordinated to the investor partners within our investment partnerships, partially offset by a $15.9 million increase attributable to higher natural gas production volumes. Total oil and natural gas liquids revenues were $12.5 million for the year ended December 31, 2010, a decrease of $1.8 million from $14.3 million for the year ended December 31, 2008. This decrease resulted primarily from a $3.2 million decrease attributable to lower average oil realized prices, partially offset by a $1.2 million increase from the sale of natural gas liquids and a $0.2 million increase associated with higher oil production volumes. The increase in natural gas volumes was the result of an increase in the production we received from our Marcellus Shale horizontal wells, which comprised a higher share of our wells drilled during the year ended December 31, 2009 as compared with the prior year comparable period.

Appalachia production costs were $25.0 million for the year ended December 31, 2009, a decrease of $0.1 million from $25.1 million for the year ended December 31, 2008. This decrease was principally due to an increase of $2.0 million 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 $1.9 million associated with labor, water hauling and disposal and other costs associated with the growth of our operations. Michigan/Indiana production costs were $0.5 million for the year ended December 31, 2009.

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 nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010, 2009 and 2008. There were no exploratory wells drilled during the years ended December 31, 2010, 2009 and 2008 and the nine months ended September 30, 2011 and 2010:

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Drilling partnership investor capital:					
Raised	$32,459	$149,342	$149,342	$353,444	$438,400
Deployed	$64,336	$176,685	$206,802	$372,045	$415,036
Gross partnership wells drilled:					
Appalachia	12	19	22	174	818
New Albany/Antrim	—	57	66	93	5
Niobrara	50	6	29	—	—
Total	62	82	117	267	823
Net partnership wells drilled:					
Appalachia	11	19	21	159	772
New Albany/Antrim	—	49	58	84	4
Niobrara	50	6	29	—	—
Total	61	74	108	243	776

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):

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Average construction and completion:					
Revenue per well	$1,075	$ 1,744	$ 1,600	$ 1,531	$ 535
Cost per well	915	1,478	1,356	1,299	463
Gross profit per well	$ 160	$ 266	$ 244	$ 232	$ 72
Gross profit margin	$9,582	$26,961	$31,555	$56,499	$55,427
Partnership net wells associated with revenue recognized(1):					
Appalachia	8	42	44	166	773
New Albany/Antrim	3	54	63	77	3
Niobrara	49	5	22	—	—
	60	101	129	243	776

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

Nine Months Ended September 30, 2011 Compared with the Nine Months Ended September 30, 2010. Well construction and completion segment margin was $9.6 million for the nine months ended September 30, 2011, a decrease of $17.4 million from $27.0 million for the nine months ended September 30, 2010. This decrease consisted of an $11.0 million decrease related to fewer wells recognized for revenue within the investment partnerships and a $6.4 million decrease associated with lower gross profit per well. Average cost and revenue per well decreased between periods due to higher capital deployed for Niobrara formation wells within the drilling partnerships during the first nine months of 2011, while the first nine months of 2010 were characterized by higher Marcellus Shale and New Albany/Antrim Shale wells. Typically, the Niobrara formation wells we have drilled within the drilling partnerships have a lower cost per well as compared to the Marcellus Shale and New Albany/Antrim Shale wells. In addition, the decrease in well construction and completion margin was the result of the cancellation of our Fall 2010 drilling program, which was the result of Atlas Energy'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. Since our drilling contracts with the investment partnerships are on a "cost-plus" basis (typically cost-plus 18%), 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. 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.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008. Well construction and completion segment margin was $56.5 million for the year ended December 31, 2009, an increase of $1.1 million from $55.4 million for the year ended December 31, 2008. This increase was due to a $39.2 million increase associated with an increase in the gross profit per well, partially offset by a $38.1 million decrease associated with a reduction in the number of wells drilled within the investment partnerships. Since our drilling contracts with the investment partnerships are on a "cost-plus" basis (typically cost-plus 18%), 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. Average cost and revenue per well have increased due to a shift from drilling less expensive shallow wells to more expensive deep or horizontal shale wells in both Appalachia and Michigan/Indiana during the year ended December 31, 2009 in comparison to the prior year.

Our consolidated balance sheet at September 30, 2011 includes $33.2 million of "liabilities associated with drilling contracts" for funds raised by our investment partnerships that have not been applied to the completion of wells due to the timing of drilling operations, and thus had not been recognized as well construction and completion revenue on our consolidated statements of operations. We expect to recognize this amount as revenue during the remainder of 2011 and the early part of 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.

Nine Months Ended September 30, 2011 Compared with the Nine Months Ended September 30, 2010. Administration and oversight fee revenues were $5.1 million for the nine months ended September 30, 2011, a decrease of $2.4 million from $7.5 million for the nine months ended September 30, 2010. This decrease was primarily due to a decrease in the number of Marcellus Shale and New Albany Shale wells drilled during the current year period in comparison to the prior year period, partially offset by the increase in the number of wells drilled in the Niobrara Shale during the current year period in comparison to the prior year period. In addition, the decrease in administration and oversight margin was the result of the cancellation of our Fall 2010 drilling program, which was the result of Atlas Energy'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.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008. Administration and oversight fee revenues were $15.6 million for the year ended December 31, 2009, a decrease of $3.7 million from $19.3 million for the year ended December 31, 2008. This decrease was primarily the result of fewer wells drilled during 2009 in comparison to the prior year, partially offset by an increase in the number of Marcellus Shale wells drilled, for which we earn higher fees from our partnership management activities in comparison to conventional wells.

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.

Nine Months Ended September 30, 2011 Compared with the Nine Months Ended September 30, 2010. Well services revenues were $15.1 million for the nine months ended September 30, 2011, a decrease of $0.5 million from $15.6 million for the nine months ended September 30, 2010. Well services expenses were $6.1 million for the nine months ended September 30, 2011, a decrease of $1.6 million from $7.7 million for the nine months ended September 30, 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 nine months ended September 30, 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.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008. Well services revenues were $17.9 million for the year ended December 31, 2009, a decrease of $0.6 million from $18.5 million for the year ended December 31, 2008. Well services expenses were $9.3 million for the year ended December 31, 2009, a decrease of $1.4 million from $10.7 million for the year ended December 31, 2008. These decreases were primarily attributable to a decrease in the number of wells drilled through our investment partnership programs, which resulted in fewer ongoing maintenance projects.

Gathering

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%.

Nine Months Ended September 30, 2011 Compared with the Nine Months Ended September 30, 2010. Our net gathering and processing expense for the nine months ended September 30, 2011 was $2.3 million compared with $5.1 million for the nine months ended September 30, 2010. This favorable decrease was principally due to lower natural gas volume and prices between the periods (see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Gas and Oil Production" beginning on page 102).

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 will generally exceed the revenues collected from the investment partnerships by approximately 3%.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008. Our net gathering and processing expense for the year ended December 31, 2009 was $6.4 million compared with no net margin for the year ended December 31, 2008. This unfavorable increase was principally due to the formation in June 2009 of our third-party gathering system agreement, whereby our gathering expenses in the Appalachian Basin will generally exceed the revenues collected from the investment partnerships by approximately 3%.

Other Costs and Expenses

General and Administrative Expenses

Nine Months Ended September 30, 2011 Compared with the Nine Months Ended September 30, 2010. General and administrative expenses were $12.3 million for the nine months ended September 30, 2011, compared with $8.5 million for the nine months ended September 30, 2010. The $3.8 million increase was principally due to $2.1 million of syndication expenses related to the cancellation of our Fall 2010 drilling program and $1.7 million increase of other salary and wages expense and other corporate 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.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008. General and administrative expenses were $15.8 million for the year ended December 31, 2009 compared with $13.1 million for the year ended December 31, 2008. The $2.7 million increase was principally due to an increase of salary and wages expense and other corporate activities.

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization decreased to $24.0 million for the nine months ended September 30, 2011 compared with $31.9 million for the nine months ended September 30, 2010, due primarily to a $7.5 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 year ended December 31, 2009, due primarily to a $3.4 million decrease in our depletion expense. Total depreciation, depletion and amortization increased to $43.7 million for the year ended December 31, 2009 compared with $39.8 million for the year ended December 31, 2008, due primarily to a $3.4 million increase in our depletion expense.

The following table presents our depletion expense per Mcfe for our Appalachia and Michigan/Indiana regions for the respective periods:

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Depreciation, depletion and amortization:					
Depletion expense	$20,626	$28,052	$36,668	$40,067	$36,650
Depreciation and amortization expense	3,393	3,877	4,090	3,645	3,131
	$24,019	$31,929	$40,758	$43,712	$39,781
Depletion expense:					
Depletion expense as a percentage of gas and oil production revenue	40%	40%	39%	35%	29%
Depletion per Mcfe	$ 2.09	$ 2.45	$ 2.44	$ 2.63	$ 2.83

Depletion expense varies from period to period and is directly affected by changes in our oil and gas reserve quantities, production levels, product prices and changes in the depletable cost basis of our oil and gas properties. For the nine months ended September 30, 2011, depletion expense decreased $7.5 million to $20.6 million compared with $28.1 million for the nine months ended September 30, 2010. Our depletion expense of oil and gas properties as a percentage of oil and gas revenues was 40% for the nine months ended September 30, 2011, comparable with the nine months ended September 30, 2010, which was primarily due to a decrease in realized natural gas prices between periods. Depletion expense per Mcfe was $2.09 for the nine months ended September 30, 2011, a decrease of $0.36 per Mcfe from $2.45 for the nine months ended September 30, 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.

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 oil and gas properties as a percentage of oil and gas 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.

For the year ended December 31, 2009, depletion expense increased $3.4 million to $40.1 million compared with $36.7 million for the year ended December 31, 2008. Our depletion expense of oil and gas properties as a percentage of oil and gas revenues was 35% for the year ended December 31, 2009, compared with 29% for the year ended December 31, 2008. Depletion expense per Mcfe was $2.63 for the year ended December 31, 2009, a decrease of $0.20 per Mcfe from $2.83 for the year ended December 31, 2008. Depletion expense increased between periods principally due to an overall increase in production volumes.

Asset Impairment

During the year ended December 31, 2010, we recognized a $50.7 million asset impairment related to oil and gas properties within property, plant and equipment on the 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 oil and gas properties being in excess of our estimate of their fair value at December 31, 2010. The estimate of fair value of these oil and gas properties was impacted by, among other factors, the deterioration of natural gas prices (see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates” beginning on page 118 for further discussion of our impairment testing).

During the year ended December 31, 2009, we recognized a $156.4 million asset impairment related to oil and gas properties within property, plant and equipment on the consolidated balance sheet for our shallow natural gas wells in the Upper Devonian shale. This impairment related to the carrying amount of these oil and gas properties being in excess of our estimate of their fair value at December 31, 2009. The estimate of fair value of these oil and gas properties was impacted by, among other factors, the deterioration of natural gas prices (see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates” beginning on page 118 for further discussion of our impairment testing).

Loss on Asset Sales

During the nine months and year ended December 31, 2010, we recognized $2.9 million loss in loss on asset sales, which was related to a loss on a sale of processing assets in Tennessee.

Liquidity and Capital Resources

General

Historically, our primary sources of liquidity have been cash generated from operations and capital raised through investment partnerships. In addition, we anticipate entering into a senior secured revolving credit facility simultaneously with the closing of the separation and related transactions, the borrowings under which will also be a primary source of liquidity (see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Proposed Credit Facility” beginning on page 114 and “Credit Agreement” beginning on page 219). Also following the closing of the separation and related transactions, we intend to make cash distributions to our general partner and limited partners at an initial distribution rate of $0.40 per unit per quarter ($1.60 per unit on an annualized basis—see “Cash Distribution Policy” beginning on page 67). Our primary cash requirements, in addition to normal operating expenses, are for capital expenditures and, subsequent to the completion of the separation and related transactions, debt service and quarterly distributions to our common unitholders. 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, subsequent to the completion of the separation and related transactions, the senior secured credit facility we anticipate entering into 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 proposed credit facility and other borrowings, the issuance of additional common units, the sale of assets and other transactions.

Proposed Credit Facility

Simultaneously with the closing of the separation and related transactions, we anticipate entering into a senior secured revolving credit facility. We anticipate that the credit facility will be substantially similar to Atlas Energy's current credit facility and that it will allow us to borrow up to the determined amount of the borrowing base, which will be based upon the loan collateral value assigned to our various natural gas and oil properties and other assets. For a description of the anticipated terms of the proposed credit facility, see "Credit Agreement" beginning on page 219.

Cash Flows—Nine Months Ended September 30, 2011 Compared with Nine Months Ended September 30, 2010

Net cash provided by operating activities of $41.6 million for the nine months ended September 30, 2011 represented an unfavorable movement of $58.5 million from net cash provided by operating activities of $100.1 million for the comparable prior year period. Net cash provided by operating activities for the nine months ended September 30, 2011 included $92.2 million in net income excluding non-cash items, which represented a $9.5 million favorable movement over the comparable prior year period. The $9.5 million favorable movement in net income excluding non-cash items included a $43.5 million favorable movement in non-cash gain on derivatives, partially offset by a $23.2 million decrease in net income, a $7.9 million unfavorable movement in depreciation, depletion and amortization expense and a $2.9 million decrease in loss on asset sales. The $9.5 million favorable movement in net income excluding non-cash items was partially offset by a $68.0 million unfavorable movement in working capital. The $68.0 million unfavorable movement in working capital was principally due to the cancellation of our Fall 2010 drilling program, which was the result of Atlas Energy's announcement of the acquisition of the Transferred Business in November 2010.

Net cash used in investing activities of $36.3 million for the nine months ended September 30, 2011 represented a favorable movement of $34.2 million from net cash used in investing activities of $70.5 million for the comparable prior year period. This favorable movement was principally due to a $34.4 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" beginning on page 116.

Net cash provided by financing activities of $54.6 million for the nine months ended September 30, 2011 represented a favorable movement of $84.2 million from net cash used in financing activities of $29.6 million for the comparable prior year period. This movement was principally due to a net increase in the net investment received from Old Atlas.

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 included a $92.5 million unfavorable movement in working capital. 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" beginning on page 116.

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 Old Atlas.

Cash Flows—Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

Net cash provided by operating activities of $192.2 million for the year ended December 31, 2009 represented a favorable movement of $22.9 million from net cash provided by operating activities of $169.3 million for the comparable prior year period. The $22.9 million favorable movement in net cash provided by operating activities included a $54.7 million favorable movement in working capital. The $54.7 million favorable movement in working capital was principally due to a $52.4 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, 2009, which were principally funded with drilling partnership capital raised during the year ended December 31, 2008. In addition, the favorable movement in working capital was impacted by the absence during the year ended December 31, 2009 of a $44.3 million unfavorable movement in subscriptions receivable from drilling partnerships recorded during the year ended December 31, 2008. The favorable movement in working capital was partially offset by a $42.0 million unfavorable movement in liabilities associated with drilling contracts, which consisted of an $85.0 million decrease in drilling partnership capital raised between periods and was partially offset by a decrease in drilling partnership capital deployed of $43.0 million. Net cash provided by operating activities for the year ended December 31, 2009 also included $142.7 million in net income excluding non-cash items, which represented a $31.8 million unfavorable movement over the comparable prior year period. The $31.8 million unfavorable movement in net income excluding non-cash items included a $186.1 million decrease in net income, partially offset by a $156.4 million increase in non-cash charges related to asset impairment, a $6.0 favorable movement in non-cash gain on derivatives and a $3.9 million favorable movement in depreciation and amortization expense.

Net cash used in investing activities of $98.4 million for the year ended December 31, 2009 represented a favorable movement of $163.8 million from net cash used in investing activities of $262.2 million for the comparable prior year period. This unfavorable movement was principally due to a $164.8 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" beginning on page 116.

Net cash used in financing activities of $93.8 million for the year ended December 31, 2009 represented an unfavorable movement of $186.7 million from net cash provided by financing activities of $92.9 million for the comparable prior year period. This movement was principally due to a change in the net investment received from Old Atlas.

Capital Requirements

Our capital requirements consist primarily of capital expenditures we make to maintain and expand our capital asset base for longer than the short-term and include new leasehold interests and the development and exploitation of existing leasehold interests through acquisitions and investments in our drilling partnerships.

During the nine months ended September 30, 2011, we had $36.3 million of capital expenditures compared with $70.7 million for the nine months ended September 30, 2010. The decrease was principally due to a $21.1 million decrease in investments in the drilling partnerships, which were $26.5 million for the nine months ended September 30, 2011 compared with $47.6 million for the prior year comparable period, a $7.5 million decrease in leasehold acquisition costs, which were $2.6 million for the nine months ended September 30, 2011 compared with $10.1 million for the comparable prior year period, a $7.4 million decrease in gathering and processing costs, which were $3.2 million for the nine months ended September 30, 2011 compared with $10.6 million for the comparable prior year period, partially offset by a $1.6 million increase in corporate and other costs, which were $4.0 million for the nine months ended September 30, 2011 compared with $2.4 million for the prior year comparable period. The decrease in investments in the drilling partnerships and gathering and processing costs was the result of the cancellation of the Fall 2010 drilling program.

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 drilling 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 drilling 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 2009.

During the year ended December 31, 2009, we had $99.3 million of capital expenditures compared with $264.1 million for the year ended December 31, 2008. The decrease was principally due to a $153.9 million decrease in investments in the drilling partnerships, which were $89.4 million for the year ended December 31, 2009 compared with $243.3 million for the prior year, and a $7.4 million decrease in gathering and processing costs, which were $9.9 million for the year ended December 31, 2009 compared with $17.3 million for the prior year. The decrease in investments in the drilling partnerships and gathering and processing costs was the result of a decrease in number of wells drilled, which was the result of a decrease in the funds raised through our investment partnerships, partially offset by a shift towards drilling larger, higher producing horizontal wells.

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.

At September 30, 2011, we are committed to expend approximately $1.5 million on drilling and completion expenditures, pipeline extensions, compressor station upgrades and processing facility upgrades.

Off-Balance Sheet Arrangements

At September 30, 2011, our off-balance sheet arrangements were limited to our commitment to expend approximately $1.5 million on drilling and completion expenditures, pipeline extensions, and compressor station upgrades and processing facility upgrades.

Cash Distributions

Following the closing of the separation and the distribution, we intend to make cash distributions to our general partner and limited partners at an initial distribution rate of $0.40 per unit per quarter ($1.60 per unit on an annualized basis). As required by our partnership agreement, we expect to distribute all of our available cash, as defined in our partnership agreement. As a result, we expect that we will rely upon external financing sources, including commercial borrowings and other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations at December 31, 2010 (in thousands):

		Payments Due By Period			
Contractual cash obligations:	**Total**	**Less than One Year**	**One to Three Years**	**Four to Five Years**	**After Five Years**
Operating leases	$12,919	$ 2,150	$4,019	$2,343	$4,407
Total contractual cash obligations	$12,919	$ 2,150	$4,019	$2,343	$4,407

		Amount of Commitment Expiration Per Period			
Other commercial commitments:	**Total**	**Less than One Year**	**One to Three Years**	**Four to Five Years**	**After Five Years**
Other commercial commitments(1)	$65,072	$65,072	$ —	$ —	$ —
Total commercial commitments	$65,072	$65,072	$ —	$ —	$ —

(1) Other commercial commitments relate to estimated well drilling and completion expenditures related to our spring 2010 S-28 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.

Internal Controls and Procedures

We are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes-Oxley Act of 2002, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a publicly traded partnership, we will be required to comply with the SEC's rules implementing Sections 302 and 404 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal controls over financial reporting. Though we will be required to disclose changes made to our internal controls and procedures on a quarterly basis, we will not be required to make our first annual assessment of our internal controls over financial reporting pursuant to Section 404 until the year following our first annual report required to be filed with the SEC. To comply with the requirements of being a publicly traded partnership, we will need to implement additional internal controls, reporting systems and procedures and hire additional accounting, finance and legal staff.

Further, our independent registered public accounting firm is not yet required to formally attest to the effectiveness of our internal controls over financial reporting until the year following our first annual report required to be filed with the SEC. If it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed or operating. Our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future.

We have no history operating as a publicly traded company. As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, including certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE, with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will require a significant amount of time from our general partner's board of directors and management and will significantly increase our legal and financial compliance costs and make such compliance more time-consuming and costly. We will need to:

- institute a more comprehensive compliance function;

- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the New York Stock Exchange;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- establish an investor relations function.

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 have identified the following policies as critical to our business operations and the understanding of our results of operations.

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 "Forward Looking Statements" beginning on page 59.

During the year ended December 31, 2010, we recognized a $50.7 million asset impairment related to oil and gas properties within property, plant and equipment on our combined balance sheet for our shallow natural gas wells in Tennessee and Ohio. During the year ended December 31, 2009, we recorded a $156.4 million asset impairment related to oil and gas properties within property, plant and equipment on our combined balance sheet for shallow natural gas wells in the Upper Devonian shale. These impairments related to the carrying amount of these oil and gas properties being in excess of our estimate of their fair value at December 31, 2010 and 2009, respectively. The estimate of the fair value of these oil and gas properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement. There were no impairments of proved oil and gas properties recorded by us for the year ended December 31, 2008.

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, 2010, 2009 and 2008.

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 ("AROs") that are defined as Level 3. Estimates of the fair value of AROs 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.

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 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 changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We and our subsidiaries 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 September 30, 2011. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties related to our commodity derivative contracts are banking institutions or their affiliates. 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.

Our market risk exposure to commodities is due to the fluctuations in the price of natural gas, oil and natural gas liquids and the impact those price movements have on our financial results. 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, oil and natural gas liquids 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, oil and natural gas liquids 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, oil and natural gas liquids 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, oil and natural gas liquids would result in a change to our net income for the twelve-month period ending September 30, 2012 of approximately $3.4 million.

Realized pricing of our natural gas, oil and natural gas liquids production is primarily driven by the prevailing worldwide prices for 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, oil and natural gas liquids 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 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 September 30, 2011, we had the following commodity derivatives:

Natural Gas Fixed Price Swaps

Production Period Ending December 31,	Volumes	Average Fixed Price
	(mmbtu)[(1)]	*(per mmbtu)[(1)]*
2011	1,560,000	$4.484
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	Average Floor and Cap
		(mmbtu)(1)	*(per mmbtu)*(1)
2011	Puts purchased	810,000	$3.933
2011	Calls sold	810,000	$5.584
2012	Puts purchased	1,920,000	$4.250
2012	Calls sold	1,920,000	$6.084
2013	Puts purchased	3,120,000	$4.750
2013	Calls sold	3,120,000	$6.065
2014	Puts purchased	1,440,000	$4.700
2014	Calls sold	1,440,000	$5.930
2015	Puts purchased	1,440,000	$4.900
2015	Calls sold	1,440,000	$6.230

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes	Average Floor and Cap
		(Bbl)(1)	*(per Bbl)*(1)
2011	Puts purchased	15,000	$ 90.000
2011	Calls sold	15,000	$125.312
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.

BUSINESS

Overview

We are a limited partnership and 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 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.

We were formed in October 2011 to own and operate substantially all of the current natural gas and oil assets and the partnership management business of Atlas Energy. 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 upon completion of the separation and distribution.

As of September 30, 2011, our principal assets consisted of:

- working interests in approximately 9,500 gross producing natural gas and oil wells;
- overriding royalty interests in approximately 630 gross producing natural gas and oil wells;
- net daily production of 36.2 Mmcfed for the nine months ended September 30, 2011;
- proved reserves of 187.1 Bcfe at December 31, 2010; 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.

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 four year period ended December 31, 2010, we raised over $1.3 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 September 30, 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 7% 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 35% of our segment margin in the twelve months ended September 30, 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*. Through our predecessors, 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.

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 nine months ended September 30, 2011, the average premium over NYMEX for natural gas delivered to our primary delivery points in the Appalachian Basin was $0.37 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 nine months ended September 30, 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 September 30, 2011, we had an interest in approximately 219 wells, consisting of 205 vertical wells and 14 horizontal wells. An additional 13 wells, consisting of eight vertical wells and five horizontal wells, have been completed and are scheduled to be turned on-line during the fourth quarter of 2011 and the first quarter of 2012.

Additionally, as of September 30, 2011, we had drilled 11 Marcellus Shale wells to total depth that we have not yet turned on-line. These wells are scheduled to be completed and turned on-line during the fourth quarter of

2011 and the first quarter of 2012. As of September 30, 2011, we are drilling 13 additional Marcellus Shale wells 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 Corporation. We believe that opportunities exist to expand our Marcellus Shale position in compliance with the non-competition agreements. We plan on drilling additional Marcellus Shale wells in this area of West Virginia during the first quarter of 2012.

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 over 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 2011 and 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 over 2,100 wells in Ohio and operate three field offices which we intend to use for future Utica Shale development.

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 September 30, 2011, we have an interest in 95 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 will 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-Julesburg 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 18% 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 23% and 41%. The following table presents our total net natural gas, oil and natural gas liquids production volumes and production per day during the nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010, 2009 and 2008:

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Production per day:(1)(2)					
Natural gas (Mcfd)	31,687	36,610	35,855	38,644	32,791
Oil (Bpd)	296	391	373	427	423
Natural gas liquids (Bpd)	449	493	499	101	—
Total (Mcfed)	36,158	41,914	41,090	41,814	35,327

(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.

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, 2010. The following table presents our production revenues and average sales prices for our natural gas, oil and natural gas liquids production for the nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010, 2009 and 2008, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Production revenues (in thousands):					
Natural gas revenue	$38,383	$57,801	$75,630	$100,526	$112,809
Oil revenue	7,341	8,080	10,541	11,119	14,274
Natural gas liquids revenue	5,930	4,935	6,879	1,334	—
Total revenues	$51,654	$70,816	$93,050	$112,979	$127,083
Average sales price:[1]					
Natural gas (per Mcf):					
Total realized price, after hedge[2]	$ 5.24	$ 7.15	$ 7.08	$ 7.54	$ 9.40
Total realized price, before hedge[2]	$ 4.69	$ 4.74	$ 4.60	$ 4.04	$ 9.63
Oil (per Bbl):					
Total realized price, after hedge	$ 90.65	$ 75.66	$ 77.31	$ 71.34	$ 92.28
Total realized price, before hedge	$ 89.79	$ 69.07	$ 71.34	$ 57.41	$ 91.71
Natural gas liquids (per Bbl) total realized price	$ 48.43	$ 36.67	$ 37.78	$ 36.19	—
Production costs (per Mcfe):[1]					
Lease operating expenses[3]	$ 1.01	$ 1.27	$ 1.27	$ 1.10	$ 1.06
Production taxes	0.05	0.03	0.04	0.03	0.03
Transportation and compression	0.48	0.58	0.65	0.68	0.85
Total	$ 1.55	$ 1.89	$ 1.96	$ 1.80	$ 1.94

(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 nine months ended September 30, 2011 and 2010 and the years ended December 31, 2010 and 2009. Including the effect of this subordination, the average realized gas sales price were $4.44 per Mcf ($3.89 per Mcf before the effects of financial hedging) and $5.78 per Mcf ($3.47 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business —Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

(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 $0.67 per Mcfe ($1.21 per Mcfe for total production costs) and $0.86 per Mcfe ($1.47 per Mcfe for total production costs for the nine months ended September 30, 2011 and 2010, respectively, and $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, 2010 and 2009, respectively. There was no subordination of production revenue to investor partners within our investment partnerships for the year ended December 31, 2008. Please read "Risk Factors—Risks Relating to Our Business —Our revenues may decrease if investors in our investment partnerships do not receive a minimum return" beginning on page 40 and Note 9 on page F-33.

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 18% 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 23% to 41%.

Over the last four years, we raised over $1.3 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 four years are summarized in the following table (amounts in millions):

	Drilling Program Capital		
Years Ended December 31,	**Investor Contributions**	**Our Contributions**	**Total Capital**
2010[1]	$ 149.3	$ 39.5	$ 188.8
2009	353.4	97.5	450.9
2008	438.4	146.3	584.7
2007	363.3	137.6	500.9
Total	$1,304.4	$420.9	$1,725.3

(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. 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.

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, 2010, 2009 and 2008 or the nine months ended September 30, 2011 and 2010.

	Nine Months Ended September 30,		Years Ended December 31,		
	2011	2010	2010	2009	2008
Gross wells drilled	62	82	117	267	823
Our share of gross wells drilled(1)	14	22	34	68	274

(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.

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 an 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, Michigan and Indiana, 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.

The following table sets forth information about our developed and undeveloped natural gas and oil acreage as of September 30, 2011. The information in this table includes our proportionate interest in acreage owned by investment partnerships.

	Developed acreage(1)		**Undeveloped acreage(2)**	
	Gross(3)	**Net(4)**	**Gross(3)**	**Net(4)**
Pennsylvania	154,492	154,492	—	—
Ohio(5)	104,612	75,619	31,608	31,608
Indiana	33,916	29,033	174,572	104,712
Tennessee	20,832	18,921	93,781	93,781
New York	20,501	15,031	11,412	11,412
Other	24,183	8,926	12,541	8,011
Total	358,536	302,022	323,914	249,524

(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 acre.
(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 September 30, 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. All rights of way in Ohio in which we will acquire an interest from Atlas Energy in connection with the separation will remain subject to Atlas Energy's priority right to develop and/or utilize such rights. We do not believe that any of these burdens will materially interfere with our use of our properties.

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, 2010. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, directly or through our ownership interests in investment partnerships, and net wells are the sum of our fractional working interests in gross wells, based on the percentage interest we own in the investment partnership that owns the well:

	Number of productive wells(1)	
	Gross	Net
Appalachia:		
Gas wells	7,901	3,248
Oil wells	505	314
Total	8,406	3,562
New Albany/Antrim:		
Gas wells	144	40
Oil wells	—	—
Total	144	40
Niobrara:		
Gas wells	8	3
Oil wells	—	—
Total	8	3
Total:		
Gas wells	8,053	3,291
Oil wells	505	314
Total	8,558	3,605

(1) Includes our proportionate interest in wells owned by 96 investment partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 529 wells.

Natural Gas and Oil Reserves

The following tables summarize information regarding our estimated proved natural gas and oil reserves as of December 31, 2010. 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. 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, 2010 is included as Exhibit 99.2 to the registration statement of which this document forms a part. 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 reported on the basis of the unweighted 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,	
	2010	2009
Natural gas (per Mcf)	$ 4.38	$ 3.87
Oil (per Bbl)	$79.43	$61.18

The adjusted weighted average prices calculated in our reserve report are as follows as of the dates indicated:

	December 31,	
	2010	2009
Natural gas (per Mcf)(1)	$ 4.63	$ 4.14
Oil (per Bbl)(1)	$72.70	$55.04

(1) The price of natural gas has been adjusted for basis premium and Btu content to arrive at the appropriate net price. The oil price has been 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. Reserve reports of other engineers might differ from the reports of our consultants, Wright and Company, Inc.

The preparation of our natural gas and oil reserve estimates were completed in accordance with our prescribed internal control procedures by Atlas Energy's reserve engineers. The accompanying reserve information included below is attributable to our reserves and was derived from the reserve reports prepared for Atlas Energy's and/or Old Atlas' annual report on Form 10-K for the years ended December 31, 2010 and 2009. For these periods, Wright and Company, Inc., an independent third-party reserve engineer, was retained to prepare a report of proved reserves related to Old Atlas. 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 and Tennessee. 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 its 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 its Executive Vice President.

Results of drilling, testing and production subsequent to the date of the estimate may justify revision of this estimate. 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 "Risk Factors—Risks Relating to Our Business" beginning on page 28. 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.

	Proved natural gas and oil reserves at December 31,	
	2010	**2009**
Proved reserves:		
Natural gas reserves (Mmcf):		
Proved developed reserves	137,393	140,392
Proved undeveloped reserves[1]	38,672	43,263
Total proved reserves of natural gas	176,065	183,655
Oil reserves (Mbbl):		
Proved developed reserves	1,833	1,786
Proved undeveloped reserves[1]	—	37
Total proved reserves of oil[2]	1,833	1,823
Total proved reserves (Mmcfe)	187,056	194,593
Standardized measure of discounted future cash flows (in thousands)[3]	$236,630	$178,818

(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 23% 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 100 Mbbl of natural gas liquids proved reserves.
(3) Amount does not include financial hedge transactions.

Results of drilling, testing and production subsequent to the date of the estimate may justify revision of this estimate. Future prices received from the sale of natural gas and oil may be different from those estimated by our independent petroleum engineering firm in preparing their 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. 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.

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, 2010, we had 51 PUD locations totaling approximately 38.7 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.

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 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, 2010 were due to the following:

- New PUDS of approximately 38.5 Bcfe were acquired;
- Conversion of approximately 8.8 Bcfe from PUDs to proved developed reserves; and
- Negative revisions of approximately 34.5 Bcfe in PUDs primarily due to the discontinuation of drilling plans in the Clinton/Medina and Upper Devonian formations over the next five years.

Development Costs. Costs incurred related to the development of PUDs were approximately $80.1 million, $80.2 million, and $216.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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 nine months ended September 30, 2011, Chevron Corporation and Atmos Energy accounted for approximately 41% and 15% of our total natural gas 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 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.

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 proposed new credit facility will 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, which agreements we will assume from Atlas Energy prior to closing: (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 will 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 generally the same as the gathering fee required under the terminated agreements, 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.

The provisions in the Gathering Agreements regarding the allocation of responsibility for constructing additional flowline are substantially the same as the provisions in the terminated agreements. 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 fiscal 2010 and the nine months ended September 30, 2011, we faced no shortage of these goods and services. Over the past several years, we and other oil and natural gas companies have experienced higher drilling and operating costs. We cannot predict the duration or stability of the current level of supply and demand for drilling rigs and other goods and services required for our operations with any certainty due to numerous factors affecting the energy industry, including the demand for natural gas and oil.

In connection with the separation, we will assume certain agreements pursuant to which subsidiaries of Chevron Corporation 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. 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, 2012. The agreement may continue from month to month thereafter, subject to the right of either party to cancel the agreement at any time following the expiration of the initial term.

Competition

The energy industry is intensely competitive in all of its aspects. We operate in a highly competitive environment for acquiring properties and other 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.

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 "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 nine months ended September 30, 2011 and fiscal 2010, 2009 and 2008, 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. The previous owners of our assets have in the past drilled a greater number of wells during the winter months, because they have typically received the majority of funds from the 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, 2010, 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 2011, or that will otherwise have a material impact on our financial position or results of operations.

Environmental laws and regulations that could have a material impact on the natural gas and oil exploration and production industry include the following:

National Environmental Policy Act. Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, 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.

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 (NESHAPs). 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 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 rulemakings 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) 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 the company.

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

In addition to domestic regulatory developments, the United States is a participant in multi-national discussion intended to deal with the greenhouse gas issue on a global basis. To date, those discussions have not resulted in the imposition of any specific regulatory system, but such talks are continuing and may result in treaties or other multi-national agreements that could have an impact on our business.

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

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

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

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 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 $0.03 per MCF on natural and $0.24 per bbl of oil, Colorado imposes a severance tax up to 5% of the value of oil and gas severed from earth, in addition to other applicable taxes, while West Virginia imposes a 5% severance tax on oil and gas. Although Pennsylvania has not imposed a severance tax relating to the extraction of natural gas, the Pennsylvania Legislature has recently passed a law that would impose an impact fee on unconventional wells drilled in Pennsylvania. See “Risk Factors—Risks Relating to Our Business—Potential introduction of a severance tax or impact fee in Pennsylvania could materially increase our liabilities” beginning on page 38. 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 allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, the type of wells that may be drilled in the future in proximity to existing wells and to limit the number of wells or locations from which we can drill.

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 403 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.

Legal Proceedings

We are party to various routine legal proceedings arising in the ordinary course of our business. We do not believe that any of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations.

MANAGEMENT

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, Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275, c/o Chair, Audit Committee.

The independent board members will 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 December 1, 2011 with respect to those persons who are expected to serve as the officers of and on the board of directors of, our general partner following the separation. The nominees for election to the board of directors of our general partner will be presented to the sole equityholder of our general partner, Atlas Energy, for election. Atlas Energy's general partner, Atlas Energy GP, LLC, is a wholly owned subsidiary of Atlas Energy. Consequently, Atlas Energy's unitholders are entitled to elect the members of the board of directors of Atlas Energy's 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

Name	Age	Position(s)
Anthony Coniglio	43	Director
DeAnn Craig	60	Director
Jeffrey C. Key	46	Director
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
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, Land
Roger R. Myers	54	Vice President of Completion Services
Joel S. Heiser	45	General Counsel and Assistant Secretary
Jeffrey M. Slotterback	29	Chief Accounting Officer

Edward E. Cohen, Chairman of the Board and Chief Executive Officer

Edward 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; was a director of TRM Corporation (a publicly traded consumer services company) from 1998 to July 2007; 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. We anticipate that Edward Cohen will initially devote a majority of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Jonathan Z. Cohen, Vice Chairman of the Board

Jonathan Cohen has served as Chairman of the Board of Atlas Energy's general partner since February 2011. 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 and was a trustee and the secretary of RAIT Financial Trust (a publicly-traded real estate investment trust) from 1997, and its Vice Chairman from 2003, until December 2006. Jonathan Cohen is a son of Edward Cohen. Jonathan Cohen's financial, business and energy experience add strategic vision to the board of directors of our general partner to assist with our growth and development. We anticipate that Jonathan Cohen will initially devote a majority of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Matthew A. Jones, President, Chief Operating Officer and Director

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 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. We anticipate that Mr. Jones will initially devote substantially all of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Anthony Coniglio, Director

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. 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. His professional licenses include Series 7, 24, 63 and 79.

Dolly Ann ("DeAnn") Craig, Director

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's degrees include a Bachelor of Science degree in Mineral Engineering Chemistry in 1973, a Bachelor of Science degree in Chemical and Petroleum Refining Engineering in 1980, a Master of Science degree in Mineral Economics and Business in 2002, a Masters of International Political Economy of Resources in 2006, and an Interdisciplinary Ph.D degree in Petroleum Engineering and Operations Research in 2005, from the Colorado School of Mines. She also received a Masters of Business Administration degree from Regis University in 1987. 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, Director

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, Director

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, Chief Financial Officer

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. We anticipate that Mr. McGrath will initially devote a majority of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Daniel C. Herz, Senior Vice President of Corporate Development and Strategy

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. We anticipate that Mr. Herz will initially devote a majority of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Freddie M. Kotek, Senior Vice President

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. We anticipate that Mr. Kotek will initially devote a majority of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Lisa Washington, Chief Legal Officer and Secretary

Ms. Washington has served as Vice President, Chief Legal Officer and Secretary of Atlas Energy GP, LLC (which is 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. We anticipate that Ms. Washington will initially devote a majority of her business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Jeffrey C. Simmons, Senior Vice President of Operations

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. We anticipate that Mr. Simmons will initially devote substantially all of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Jerry Dominey, Vice President of Exploration and Chief Geologist

Mr. Dominey has served as Vice President of Exploration and Chief Geologist of Atlas Energy GP, LLC (which is 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. We anticipate that Mr. Dominey will initially devote substantially all of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Brad O. Eubanks, Vice President, Land

Mr. Eubanks has served as Vice President, Land of Atlas Energy GP, LLC (which is 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. We anticipate that Mr. Eubanks will initially devote substantially all of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Roger R. Myers, Vice President of Completion Services

Mr. Myers has served as Vice President of Completion Services of Atlas Energy GP, LLC (which is 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. We anticipate that Mr. Myers will initially devote substantially all of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Joel S. Heiser, General Counsel and Assistant Secretary

Mr. Heiser has served as the Associate General Counsel of Atlas Energy GP, LLC (which is 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. We anticipate that Mr. Heiser will initially devote substantially all of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Jeffrey M. Slotterback, Chief Accounting Officer

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 anticipate that Mr. Slotterback will initially devote a majority of his business time directly to our business or affairs, although this amount may increase or decrease in future periods.

Composition of the Board of Directors of our General Partner

We currently expect that, upon the consummation of our separation, the board of directors of our general partner will consist of seven members, approximately three of whom we expect to satisfy the independence standards established by the Sarbanes-Oxley Act and the applicable rules of the SEC and the NYSE. It is anticipated that the board of directors of our general partner will meet as needed.

Committees of the Board of Directors of our General Partner

We expect that the standing committees of the board of directors of our general partner will be the audit committee and the conflicts committee. We intend to avail ourselves of certain exceptions to the listing requirements of the NYSE which are available to us as a "controlled company," due to Atlas Energy's ownership of more than 50% of our outstanding voting securities, and due to our limited partnership structure.

Audit Committee. The audit committee's duties will 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 will also approve any other services provided by public accounting firms. The audit committee will provide 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 will be 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 U.S. Securities Exchange Act of 1934, as amended, which we refer to as the Exchange Act, 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 will be available on our web site at *www.atlasresourcepartners.com*, and we will make a printed copy available to any unitholder who so requests. Mr. Coniglio, Mr. Key and Mr. Wolf are expected to be the members of the audit committee of the board of directors of our general partner. Mr. Key is expected to be the chairman of the audit committee of the board of directors of our general partner.

Conflicts Committee. The conflicts committee will review 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 conflicts committee will consist of one or more directors. Mr. Coniglio, Mr. Key and Mr. Wolf are expected to be the members of the conflicts committee of the board of directors of our general partner. Mr. Wolf is expected to be the chairman of the conflicts committee of the board of directors of our general partner.

EXECUTIVE COMPENSATION

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 will be employed and compensated by Atlas Energy. Pursuant to our partnership agreement, our general partner will manage our operations and activities through its and its affiliates' employees (including employees of Atlas Energy and its general partner), and we will reimburse our general partner for direct and indirect general and administrative expenses, including compensation expenses, incurred on our behalf (see discussion above under "Management—Reimbursement of Expenses of Our General Partner and Its Affiliates" on page 142 for more information).

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, and are expected to be 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" beginning on page 155. 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 2010, Old Atlas allocated the compensation of Atlas Energy's named executive officers between activities on behalf of Atlas Energy and Atlas Pipeline Partners and activities on behalf of itself and its other affiliates based upon an estimate of the time spent by such officers on activities for Atlas Energy and Atlas Pipeline Partners and for Old Atlas and its affiliates. Atlas Pipeline Partners reimbursed Old Atlas for the compensation allocated to it for its and Atlas Energy's named executive officers. Old Atlas did not make a separate allocation to Atlas Energy.

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

We expect that, after the completion of the separation, certain of the executive officers of our general partner will devote the majority of their time to our business (and, therefore, that 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, that less than a majority of their compensation will be reimbursable by us). The relative amount of time that our officers are expected to devote to our business is described under "Management—Board of Directors and Officers of Our General Partner Following the Separation," beginning on page 142. As disclosed in that section, we expect that 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 that 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 after completion of the separation, a majority of Atlas Energy's compensation costs for its named executive officers 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 whom we expect to 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" beginning on page 155. Our general partner is not expected to enter into any new employment agreements with any of our executive officers.

Compensation Philosophy and Objectives

As described above, we will not directly employ any of the persons responsible for managing our business. Atlas Resource Partners GP, LLC, our general partner, will manage our operations and activities, using the employees of Atlas Energy, and the board of directors and executive officers of our general partner 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) will 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" beginning on page 155. 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, L.P. pursuant to the 2012 Atlas Resource Partners, L.P. Long-Term Incentive Plan we expect to adopt prior to the separation, which plan we describe 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" beginning on page 155.

2012 Long-Term Incentive Plan

Before the consummation of the distribution, Atlas Energy, our sole unitholder, intends to deliver a written consent approving the adoption of our new equity plan. This action by Atlas Energy will be sufficient to approve the adoption of the new equity plan. The new equity plan will become effective upon the consummation of the distribution.

The new equity plan is intended to promote the interests of Atlas Resource Partners 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 Atlas Resource Partners (including employees of Atlas Energy and its general partner) incentive awards for superior performance that are based on Atlas Resource Partners common units. The new 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 Atlas Resource Partners, and to encourage them to devote their best efforts to the businesses of our general partner and Atlas Resource Partners and advancing the interests of our general partner and Atlas Resource Partners.

The following is a brief description of the principal features of the new equity plan. This summary is subject to, and qualified in its entirety by reference to, the new equity plan, which is Exhibit 10.9 to the registration statement of which this document forms a part.

Grants made under the new 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."

Subject to the provisions of the new equity plan, the committee is authorized to administer and interpret the new equity plan, to make factual determinations and to adopt or amend its rules, regulations, agreements and instruments for implementing the new equity plan. The committee will also have the full power and authority to determine the recipients of grants under the new equity plan as well as the terms and provisions of restrictions relating to grants.

Subject to any applicable law, the committee, in its sole discretion, may delegate any or all of its powers and duties under the new equity plan, including the power to award grants under the new equity plan, to the Chief Executive Officer of our general partner, subject to such limitations as the committee may impose, if any. However, the Chief Executive Officer many not make awards to, or take any action with respect to any grant previously awarded to, himself or a person who is subject to Rule 16b-3 under the Exchange Act.

Persons eligible to receive grants under the new equity plan are (i) officers and employees of our general partner, its affiliates, consultants or joint venture partners who perform services for our general partner, Atlas Resource Partners or an affiliate or in furtherance of our general partner's or Atlas Resource Partners' 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 Atlas Resource Partners common units (approximately 10% of the fully diluted issued and outstanding number of Atlas Resource Partners common units on a pro forma basis after giving effect to the distribution) may be issued under the new equity plan. This amount is subject to adjustment as provided in the new equity plan for events such as distributions (in Atlas Resource Partners common units or other securities or property, including cash), unit splits (including reverse splits), recapitalizations, mergers, consolidations, reorganizations, reclassifications and other extraordinary events affecting the outstanding Atlas Resource Partners 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 new equity plan. Atlas Resource Partners common units issued under the new equity plan may consist of Atlas Resource Partners common units newly issued by Atlas Resource Partners, Atlas Resource Partners common units acquired in the open market or from any affiliate of our general partner or Atlas Resource Partners or any other person or any combination of the foregoing. If any award granted under the new equity plan is forfeited or otherwise terminates or is canceled or paid without the delivery of Atlas Resource Partners common units, then the Atlas Resource Partners common units covered by the award will (to the extent of the forfeiture, termination, or cancellation, as the case may be) again be Atlas Resource Partners common units available for grants of awards under the new equity plan. Atlas Resource Partners common units surrendered in payment of the exercise price of an option, and Atlas Resource Partners common units withheld or surrendered for payment of taxes, will not be available for re-issuance under the new equity plan.

Awards granted under the new equity plan may consist of options to purchase Atlas Resource Partners 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.

An option is the right to purchase an Atlas Resource Partners common unit 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 an Atlas Resource Partners 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 Atlas Resource Partners 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 Atlas Resource Partners to withhold a number of Atlas Resource Partners 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 represent rights to receive an Atlas Resource Partners common unit, an amount of cash or other securities or property based on the value of an Atlas Resource Partners common unit, or a combination of Atlas Resource Partners 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 Atlas Resource Partners with respect to an Atlas Resource Partners common unit during the period that the underlying phantom unit is outstanding. Distribution equivalents may (i) be paid currently by Atlas Resource Partners 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 Atlas Resource Partners common units or in a combination of cash and Atlas Resource Partners common units, in each case as determined by the committee.

Restricted units are actual Atlas Resource Partners common units 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 Atlas Resource Partners 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 Atlas Resource Partners 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 new equity plan), all unvested awards granted under the new equity plan held by directors will immediately vest in full. In the case of awards granted under the new equity plan held by eligible employees, upon the eligible employee's termination of employment without "cause" (as defined in the new 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 Atlas Resource Partners common units that otherwise would have been unvested so that participants (as holders of awards granted under the new equity plan) may participate in the transaction;
- provide for the payment of cash or other consideration to participants in exchange for the cancellation of outstanding awards (in an amount equal to the fair market value of such cancelled awards);
- terminate all or some awards upon the consummation of the change-in-control transaction, but only if the 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 new 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.

All awards granted under the new equity plan will be subject to applicable federal (including FICA), state, and local tax withholding requirements. If our general partner so permits, Atlas Resource Partners common units may be withheld to satisfy tax withholding obligations with respect to awards paid in Atlas Resource Partners common units, at the time such awards become subject to employment taxes and tax withholding, as applicable, up to an amount that does not exceed the minimum required withholding for federal (including FICA), state and local tax liabilities. Our general partner may require forfeiture of any award for which the participant does not timely pay the applicable withholding taxes.

Subject to the limitations described below, the committee may amend, alter, suspend, discontinue or terminate the new equity plan at any time without the consent of participants, except that the committee may not amend the new equity plan without approval of the unitholders if such approval is required in order to comply with applicable stock exchange requirements. No amendment or termination of the new equity plan may materially impair any rights or obligations of participants under any previously granted awards, unless the participant has consented or such amendment or termination was reserved in the new equity plan or the applicable award agreements. The committee may not reprice options, nor may the new equity plan be amended to permit option repricing, unless the unitholders approve such repricing or amendment.

The new equity plan will continue until the date terminated by the board of directors of our general partner or the date upon which Atlas Resource Partners common units are no longer available for the grant of awards, whichever occurs first.

U.S. Federal Income Tax Consequences

The following is a general description of the U.S. federal income tax consequences of options, phantom units and restricted unit awards granted under the new equity plan. It provides only a general description of the application of federal income tax laws with respect to grants under the new equity plan. This discussion is intended for the information of Atlas Resource Partners unitholders and not as tax guidance to participants in the new equity plan. The summary does not address the effects of other federal taxes or taxes imposed under state, local or foreign tax laws and does not purport to be complete.

Options granted under the new equity plan are not eligible for treatment as "incentive stock options" under the Internal Revenue Code. Therefore, all options granted under the new equity plan will be non-qualified options. A grantee of options will not recognize income at the time of grant. Upon exercise of an option, (i) the grantee will recognize ordinary compensation income equal to the amount, if any, by which the fair market value (as determined on the date of exercise of the options) of the Atlas Resource Partners common units issuable with respect to the option exceeds the exercise price of the option (such amount, the "spread"), and (ii) Atlas Resource Partners will receive a deduction in an amount equal to the spread. The tax basis of Atlas Resource Partners common units obtained pursuant to the exercise of an option equals the option exercise price paid by the grantee plus the ordinary compensation income recognized by the grantee. The grantee's holding period for the Atlas Resource Partners common units acquired pursuant to the exercise of an option for purposes of determining eligibility for capital gains treatment upon the disposition of the Atlas Resource Partners common units begins on the option exercise date.

The recipient of a phantom unit or restricted unit award will not recognize income at the time of the grant of his or her award. Rather, the participant will have taxable compensation in an amount equal to the fair market value of the Atlas Resource Partners common units or, in the case of phantom units, the Atlas Resource Partners common units or other securities or property (as the case may be), actually received by the participant in connection with the vesting of the award, and Atlas Resource Partners will receive a deduction equal to such amount. Upon the sale of Atlas Resource Partners common units, a participant generally will have gain or loss (which may consist of both ordinary and capital gain and loss elements depending upon Atlas Resource Partners' taxable income and loss during the period in which the Atlas Resource Partners common units were held). Since Atlas Resource Partners is currently not a taxable entity for federal income tax purposes, the amount of taxable compensation to the participant will be treated as deductions allocated among the partners of Atlas Resource Partners in accordance with Atlas Resource Partners' partnership agreement.

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. Effective as of the closing of this offering, 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 Atlas Resource Partners, L.P. 2012 Long-Term Incentive 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.

Compensation Committee Interlocks and Insider Participation

Our general partner's board of directors does not intend at this time to establish a compensation committee, although a compensation committee may be established in the future.

Atlas Energy Compensation Discussion and Analysis

The following is an excerpt from Atlas Energy's executive compensation disclosures that will be 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 in this information statement 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 expected to be 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, is being presented so that relevant portion of it may be incorporated into the discussion under "Executive Compensation—Compensation Discussion and Analysis."

Board of Directors and Executive Officers of Atlas Energy's General Partner

The following table sets forth information with respect to the executive officers and directors of Atlas Energy's general partner:

Name	Age	Position with the general partner	Year in which service began	Term expires
Edward E. Cohen	73	Chief Executive Officer, President and Director	2006	2014
Sean P. McGrath	40	Chief Financial Officer	2011	—
Jonathan Z. Cohen	41	Chairman of the Board	2006	2013
Matthew A. Jones	50	Senior Vice President and President and Chief Operating Officer of E&P Division	2011	—
Eugene N. Dubay	63	Senior Vice President of Midstream	2011	—
Freddie M. Kotek	56	Senior Vice President of Investment Partnership Division	2011	
Lisa Washington	44	Vice President, Chief Legal Officer and Secretary	2011	—
Jeffrey M. Slotterback	29	Chief Accounting Officer	2011	—
Carlton M. Arrendell	50	Director	2011	2013
Mark C. Biderman	66	Director	2011	2013
Dennis A. Holtz	71	Director	2011	2012
William G. Karis	63	Director	2006	2012
Harvey G. Magarick	72	Director	2006	2012
Ellen F. Warren	55	Director	2011	2014

Edward E. Cohen was the Chairman of the Board of Atlas Energy's general partner from its formation in January 2006 until February 2011, when he became Atlas Energy's Chief Executive Officer and President. Mr. Cohen served as the Chief Executive Officer of Atlas Energy's general partner from its formation in January 2006 until February 2009. Mr. Cohen has been the Chairman of the managing board of Atlas Pipeline Partners GP, LLC ("Atlas Pipeline GP"), since its formation in 1999. From 1999 to January 2009, Mr. Cohen was the Chief Executive Officer of Atlas Pipeline GP. Mr. Cohen also was the Chairman of the Board and Chief Executive Officer of Atlas Energy, Inc. (formerly known as Atlas America, Inc.) from its organization in 2000 until the consummation of the Chevron Merger in February 2011 and also served as its President from 2000 to October 2009 when Atlas Energy Resources, LLC became its wholly-owned subsidiary following its merger transaction. Mr. Cohen was the Chairman of the Board and Chief Executive Officer of Atlas Energy Resources, LLC and its manager, Atlas Energy Management, Inc.; from their formation in June 2006 until the consummation of the Chevron Merger in February 2011. In addition, Mr. Cohen has been Chairman of the Board of Directors of Resource America, Inc. (a publicly-traded specialized asset management company) since 1990 and was its Chief Executive Officer from 1988 until 2004, and President from 2000 until 2003; Chairman of the Board of Resource Capital Corp. (a publicly-traded real estate investment trust) since its formation in September 2005 until November 2009 and still serves on its board; a director of TRM Corporation (a publicly-traded consumer services company) from 1998 to July 2007; and Chairman of the Board of Brandywine Construction & Management, Inc. (a property management company) since 1994. Mr. Cohen is the father of Jonathan Z. Cohen. Mr. Cohen has been active in the energy business since the late 1970s. Among the reasons for his appointment as a director, Mr. Cohen brings to the board the vast experience that he has accumulated through his activities as a financier, investor and operator in various parts of the country.

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

Jonathan Z. Cohen has been the Chairman of the Board of Atlas Energy's general partner since February 2011. Before that, he served as Vice Chairman of the Board of Atlas Energy's general partner from its formation in January 2006 until February 2011. Mr. Cohen has been the Vice Chairman of the managing board of Atlas Pipeline GP since its formation in 1999. Mr. Cohen also was the Vice Chairman of the Board of Atlas Energy, Inc. (formerly known as Atlas America, Inc.) from its organization in 2000 until the consummation of the Chevron Merger in February 2011. Mr. Cohen was the Vice Chairman of the Board of Atlas Energy Resources, LLC and Atlas Energy Management from their formation in June 2006 until the consummation of the Chevron Merger in February 2011. Mr. Cohen has been a senior officer of Resource America since 1998, serving as the Chief Executive Officer since 2004, President since 2003 and a director since 2002. Mr. Cohen has been Chief Executive Officer, President and a director of Resource Capital Corp. since its formation in 2005 and was a trustee and secretary of RAIT Financial Trust (a publicly-traded real estate investment trust) from 1997, and its Vice Chairman from 2003, until December 2006. Mr. Cohen is a son of Edward E. Cohen. Among the reasons for his appointment as a director, Mr. Cohen's financial, business and energy experience add strategic vision to Atlas Energy's general partner's board to assist with Atlas Energy's growth and development.

Matthew A. Jones has been Senior Vice President of Atlas Energy's general partner and President and Chief Operating Officer of Atlas Energy's exploration and production division since February 2011. Before that, he was the Chief Financial Officer from March 2005 and an Executive Vice President from October 2009 until February 2011 of Old Atlas. Mr. Jones was the Chief Financial Officer of Atlas Energy Resources and Atlas Energy Management from their formation until the consummation of the Chevron Merger in February 2011. Mr. Jones served as the Chief Financial Officer of Atlas Energy's general partner from January 2006 until September 2009 and as the Chief Financial Officer of Atlas Pipeline GP from March 2005 to September 2009. From 1996 to 2005, Mr. Jones worked in the Investment Banking Group at Friedman Billings Ramsey, concluding as Managing Director. Mr. Jones worked in Friedman Billings Ramsey's Energy Investment Banking Group from 1999 to 2005, and in Friedman Billings Ramsey's Specialty Finance and Real Estate Group from 1996 to 1999. Mr. Jones served as a director of Atlas Energy's general partner from February 2006 to February 2011. Mr. Jones is a Chartered Financial Analyst.

Eugene N. Dubay has been Senior Vice President of Midstream of Atlas Energy's general partner since February 2011. Before that, he was the Chief Executive Officer, President and a director of Atlas Energy's general partner from February 2009 until February 2011. Mr. Dubay has been President and Chief Executive Officer of Atlas Pipeline GP since January 2009. Mr. Dubay has served as a member of the managing board of Atlas Pipeline GP since October 2008, where he served as an independent member until his appointment as President and Chief Executive Officer. Mr. Dubay has been the President of Atlas Pipeline Mid-Continent, LLC since January 2009. Mr. Dubay was the Chief Operating Officer of Continental Energy Systems LLC, the parent of SEMCO Energy, from 2002 to January 2009. Mr. Dubay has also held positions with ONEOK, Inc. and Southern Union Company and has over 20 years experience in midstream assets and utilities operations, strategic acquisitions, regulatory affairs and finance. Mr. Dubay is a certified public accountant and a graduate of the U.S. Naval Academy.

Freddie M. Kotek has been a Senior Vice President of the Investment Partnership Division of Atlas Energy's general partner since February 2011. Before that, he was the Executive Vice President of Old Atlas from February 2004 until February 2011 and served as a director from September 2001 until February 2004. Mr. Kotek has been Chairman of Atlas Resources, LLC since September 2001 and has served as an Executive Vice President since October 2009. He has also served as Chief Executive Officer and President of Atlas Resources since January 2002. Mr. Kotek served as Old Atlas's Chief Financial Officer from February 2004 until March 2005. Mr. Kotek was a Senior Vice President of Resource America from 1995 until May 2004 and President of Resource Leasing, Inc. (a wholly-owned subsidiary of Resource America) from 1995 until May 2004.

Lisa Washington has been Vice President, Chief Legal Officer and Secretary of Atlas Energy's general partner since February 2011. Ms. Washington previously served as Chief Legal Officer and Secretary of Old Atlas, 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's general partner from January 2006 to October 2009 and as a Senior Vice President of Atlas Energy's general partner from October 2008 to October 2009. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Pipeline GP 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 GP 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 Vice 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 M. Slotterback has been Chief Accounting Officer of Atlas Energy's general partner since March 2011. Before that, Mr. Slotterback served as the Manager of Financial Reporting for Old Atlas from July 2009 until February 2011 and then served as the Manager of Financial Reporting for Atlas Energy's general partner from February 2011 until March 2011. Mr. Slotterback served as Manager of Financial Reporting for both Atlas Energy's general partner and Atlas Pipeline GP 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.

Carlton M. Arrendell has been a director since February 2011. Before that, he was a director of Old Atlas from February 2004 until February 2011. Mr. Arrendell has been the Chief Investment Officer and a Vice President of Full Spectrum of NY LLC since May 2007. Prior to joining Full Spectrum, Mr. Arrendell served as a special real estate consultant to the AFL-CIO Investment Trust Corporation following six years of service as Investment Trust Corporation's Chief Investment Officer. Mr. Arrendell is also an attorney admitted to practice law in Maryland and the District of Columbia. Mr. Arrendell's investment expertise is valuable to Atlas Energy's company and its subsidiaries in the pursuit of acquisitions. In addition, the board is benefitted by his strong background in finance.

Mark C. Biderman has been a director since February 2011. Before that, he was a director of Old Atlas from July 2009 until February 2011. Mr. Biderman was Vice Chairman of National Financial Partners Corp., a publicly-traded financial services company, from September 2008 to December 2008. Before that, from November 1999 to September 2008, he was National Financial's Executive Vice President and Chief Financial Officer. From May 1987 to October 1999, Mr. Biderman served as Managing Director and Head of the Financial Institutions Group at CIBC World Markets Group, an investment banking firm, and its predecessor, Oppenheimer & Co., Inc. Mr. Biderman serves as a director and chairman of the audit committee, and as a member of the corporate governance and nominating committee, of Full Circle Capital Corporation, a publicly-traded investment company, since August 2010. Mr. Biderman serves as a director and chairman of the compensation committee, and a member of the audit committee of Apollo Commercial Real Estate Finance, Inc., a publicly-traded commercial real estate finance company, since November 2010. He also serves as a director and chairman of the audit committee and a member of the nominating and corporate governance committee of Apollo Residential Mortgage, Inc., a publicly-traded residential real estate finance company, since July 2011. Mr. Biderman is a Chartered Financial Analyst. Mr. Biderman brings extensive financial expertise to the board as well as to the audit committee.

Dennis A. Holtz has been a director since February 2011. Before that, he was a director of Old Atlas from February 2004 until February 2011. Mr. Holtz maintained a corporate and real estate law practice in Philadelphia and New Jersey from 1988 until his retirement in January 2008. During that period, Mr. Holtz was counsel for or secretary of numerous private and public business entities and this extensive experience with corporate governance issues was the reason he was chosen as chairman of the nominating and governance committee. In addition, Mr. Holtz has had extensive experience with lease issues and provides valuable insight into interacting with lessors of drilling sites. Mr. Holtz served on the Old Atlas board for six years, since its spin-off from Resource America and his length of service on Old Atlas's board provides him with extensive knowledge of Atlas Energy's acquired business and industry. Since Atlas Energy's company interacts in the Appalachian region with many small firms, Mr. Holtz's experience as an operator of his own law office is believed to provide insight into interacting with smaller companies.

William G. Karis has been the principal of Karis and Associates, LLC, a consulting company that provides financial and consulting services to the coal industry, since 1997. Prior to that, Mr. Karis was President and CEO of CONSOL Inc. (now CONSOL Energy Company). Mr. Karis is a member of the Boards of Directors and is Chairman of the Audit and Finance Committees of Blue Danube Inc., and Greenbriar Minerals, LLC. Mr. Karis has extensive experience in the energy industry, primarily relating to coal. Mr. Karis' experience in the coal industry has helped the Board shape its thinking regarding the relative competition between Atlas Pipeline Partners' products in relation to other energy sources (most notably coal). Mr. Karis also brings valuable management insight in various areas based on his experience as a chief executive officer. These combined experiences and insight serve as the basis, among other reasons, for Mr. Karis' appointment as a director.

Harvey G. Magarick has maintained his own consulting practice since June 2004. From 1997 to 2004, Mr. Magarick was a partner at BDO Seidman. Mr. Magarick is a member of the Board of Trustees of the Hirtle Callaghan Trust, an investment fund, and has been the Chairman of its audit committee since 2004. Mr. Magarick brings a strong accounting background to Atlas Energy's general partner's board and, as a "financial expert", serves as the chair of Atlas Energy's audit committee. Mr. Magarick's accounting experience is critical to an understanding of the varied issues that face us. This experience, among other reasons, serves as the basis for Mr. Magarick's appointment as a director.

Ellen F. Warren has been a director since February 2011. Before that, she was a director of Old Atlas from September 2009 until February 2011. She is founder and President of OutSource Communications, a marketing communications firm that services corporate and nonprofit clients. Prior to founding OutSource Communications in August 2005, she was President of Levy Warren Marketing Media, a public relations and marketing firm she co-founded in March 1998. She was previously Vice President of Marketing/Communications for Jefferson Bank, a Philadelphia-based financial institution, from September 1992 to February 1998. Ms. Warren served as an independent member of the Board of Directors of Atlas Energy Resources, LLC from December 2006 until September 2009. Ms. Warren is a seasoned director, having previously served on the board of Atlas Energy Resources, LLC from its formation until its merger. Ms. Warren brings management, communication and leadership skills to Atlas Energy's general partner's board.

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

Jonathan Z. Cohen serves as the chairman of the board of directors of Atlas Energy's general partner and Edward E. Cohen serves as the chief executive officer and president of Atlas Energy's general partner. The board of directors of Atlas Energy's general partner believes that the most effective leadership structure at the present time is for separation of the chairman of the board of directors from the chief executive officer position. The chief executive officer contacts the chairman of the board of directors on a regular basis and provides status updates of operations during these discussions.

Overview

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

Before the consummation of the Chevron Merger, Atlas Energy did not directly compensate its executive officers. Rather, the Old Atlas 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 Old Atlas and its other affiliates. APL reimbursed Old Atlas for the compensation allocated to it; Old Atlas did not make a separate allocation to Atlas Energy.

In February 2011, in connection with separating from Old Atlas 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 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. Warren and Messrs. Arrendell and 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 Old Atlas' 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.

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%; Eugene Dubay, 2.60% and Freddie Kotek, 1.73%. Sean McGrath and Eric Kalamaras 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 the long-term incentive plan to be adopted by ARP.

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 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 Old Atlas, which are described under "Executive Compensation—Atlas Energy Compensation Discussion and Analysis—Employment Agreements and Potential Payments Upon Termination or Change of Control" beginning on page 167, and their equity holdings in Old Atlas. 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" beginning on page 161, and entered into employment agreements with Messrs. E. Cohen, J. Cohen, Jones and Dubay 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" beginning on page 167. "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 Messrs. Jones's and Dubay's respective agreements, 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 Atlas Energy's NEOs as follows: Mr. E. Cohen—$700,000, Mr. Dubay—$500,000, 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 Old Atlas.

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 Old Atlas 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 Old Atlas 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 Old Atlas 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 Old Atlas, 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. Dubay—$1,000,000, 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. 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 Old Atlas, which are described under "Executive Compensation–Atlas Energy Compensation Discussion and Analysis—Employment Agreements and Potential Payments Upon Termination or Change of Control" beginning on page 167, and their equity holdings in Old Atlas, 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. Dubay—80,000 phantom units and 100,000 options; Mr. McGrath—30,000 phantom units and 35,000 options; Mr. Kalamaras—50,000 phantom units and 70,000 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
Chief Executive Officer	2010	1,000,000	—	2,500,014	3,170,200	5,000,000	3,375	11,673,589
and President[4]	2009	983,846	—	—	—	2,500,000	134,600	3,618,446
Eugene N. Dubay,	2011	500,000	—	1,778,400[5]	993,000[6]	1,000,000	5,136,128[8]	9,407,528
Senior Vice President of	2010	500,000	1,000,000	1,334,009	1,008,700	—	26,484	3,869,193
Midstream	2009	438,846	500,000	—	564,000	—	555,805	2,058,652
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
Eric Kalamaras,	2011	274,577	—	1,111,500[5]	695,100[6]	—	94,486[11]	2,175,653
former Chief Financial	2010	274,519	180,000	660,020[12]	273,790	—	49,572	1,437,901
Officer	2009	76,923	152,917	66,620	—	—	—	296,460
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 Old Atlas and a partial year of service with Atlas Energy. The amount in this column for Mr. Kalamaras reflects a partial year of service.

(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, a position previously held by Mr. Dubay.

(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. Dubay - 80,000 phantom units; Mr. McGrath - 30,000 phantom units; Mr. Kalamaras - 50,000 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. Dubay - 100,000 options; Mr. McGrath - 35,000 options; Mr. Kalamaras - 70,000 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) Includes payments on DERs of $45,600 with respect to the phantom units awarded under Atlas Energy's Plans and $27,842 with respect to the phantom units awarded under the APL Plans. Also includes amounts paid by Chevron in connection with the termination of Mr. Dubay's employment agreement as a result of the Chevron Merger as follows: $879,712 severance and $4,182,865 for the cash-out of equity awards subject to accelerated vesting, representing 15,454 stock awards reported in the Unit awards column for 2010 and 145,000 options reported in the Options awards column for 2009 and 2010. See "Executive Compensation—Atlas Energy Compensation Discussion and Analysis—Employment Agreements and Potential Payments Upon Termination or Change of Control—Eugene N. Dubay—2009 Employment Agreement" beginning on page 178 and the 2011 Option Exercises and Stock Vested Table.
(9) On February 18, 2011, Mr. McGrath was appointed to serve in the capacity of Chief Financial Officer of Atlas Energy's general partner, a position previously held by Mr. Kalamaras.
(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) Includes payments on DERs of $16,500 with respect to the phantom units awarded under Atlas Energy's Plans and $68,820 with respect to the phantom units awarded under the APL Plans.
(12) Reflects a change from what was reported in Atlas Energy's Form 10-K for fiscal year 2010 to now reflect the cash bonus units that had been converted to phantom units during 2010.
(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
Eugene N. Dubay	N/A	N/A	3,249,000	3/25/11	80,000	—	—	1,778,400
				3/25/11	—	100,000	22.23	993,000
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
Eric Kalamaras	N/A	N/A	N/A	3/25/11	50,000[6]	—	—	1,111,500
				3/25/11	—	70,000[6]	22.23	695,100
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" beginning on page 160, 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.
(6) Units and options were forfeited upon Kalamaras' resignation effective October 31, 2011.

Employment Agreements and Potential Payments Upon Termination or Change of Control

Edward E. Cohen

2004 Employment Agreement

In May 2004, Old Atlas 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" beginning on page 159, Old Atlas 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. Old Atlas 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 Old Atlas 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 Old Atlas 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 Old Atlas 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 Old Atlas. 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.
- Old Atlas 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 Old Atlas' employees, during the three years following his termination, (c) a lump sum amount equal to the cost Old Atlas would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by Old Atlas' employees, (d) automatic vesting of all stock and option awards and (e) any amounts payable under Old Atlas' long-term disability plan.

- Old Atlas 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 Old Atlas' Board of Directors or Old Atlas' material breach of the agreement. Mr. Cohen must provide Old Atlas with 30 days' notice of a termination by him for good reason within 60 days of the event constituting good reason. Old Atlas 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 Old Atlas 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 Old Atlas' 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 Old Atlas' employees, during the three years following his termination, (iii) a lump sum amount equal to the cost Old Atlas would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by Old Atlas' employees, and (iv) automatic vesting of all stock and option awards.
- Mr. Cohen may terminate the agreement without cause with 60 days notice to Old Atlas, 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 Old Atlas' voting securities or all or substantially all of Old Atlas' 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;
- Old Atlas consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) Old Atlas' 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 Old Atlas' directors immediately before the transaction and Old Atlas; chief executive officer immediately before the transaction continues as the chief executive officer of the surviving entity; or (b) Old Atlas' voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of Old Atlas, 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 Old Atlas Board members at the beginning of the period cease for any reason to constitute a majority of the Old Atlas Board, unless the election or nomination for election by Old Atlas' 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
- Old Atlas' stockholders approve a plan of complete liquidation or winding up of Old Atlas, or agreement of sale of all or substantially all of Old Atlas' assets or all or substantially all of the assets of Old Atlas' 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, Old Atlas 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: $60,354,580 for the cash-out of the Old Atlas 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" beginning on page 187. 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" beginning on page 185. 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, Old Atlas 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" beginning on page 159, Old Atlas 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 Old Atlas 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 Old Atlas 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.
- Old Atlas 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 Old Atlas' board determines, in good faith based upon medical evidence, that he is unable to perform his duties. Upon termination by Old Atlas 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 Old Atlas 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 Old Atlas' 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 Old Atlas, (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.
- Old Atlas 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 Old Atlas 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 Old Atlas' voting securities or all or substantially all of Old Atlas' 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;

- Old Atlas consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) Old Atlas' 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 Old Atlas' directors immediately before the transaction and Old Atlas' Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) Old Atlas' voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of Old Atlas, 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 Old Atlas board members at the beginning of the period cease for any reason to constitute a majority of Old Atlas' board, unless the election or nomination for election by Old Atlas' 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
- Old Atlas' stockholders approve a plan of complete liquidation or winding up, or agreement of sale of all or substantially all of Old Atlas' 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 Old Atlas 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" beginning on page 187. 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" beginning on page 185. 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, Old Atlas 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 Old Atlas' 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 subject to forfeiture in accordance with the long-term incentive plan of the applicable entity except that, if Old Atlas 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 Old Atlas 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 Old Atlas' 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 Old Atlas 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. Old Atlas then would have 30 days in which to cure and, if it did not do so, Mr. Jones's 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's 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 Old Atlas 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 Old Atlas' voting securities or all or substantially all of Old Atlas' 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 Old Atlas 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) Old Atlas' 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 Old Atlas' directors immediately before the transaction and Old Atlas' Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) Old Atlas' voting securities immediately before the transaction represent less than 60% of the combined voting power immediately after the transaction of Old Atlas, 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 Old Atlas' 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
- Old Atlas' stockholders approve a plan of complete liquidation or winding-up, or agreement of sale of all or substantially all of Old Atlas' assets or all or substantially all of the assets of Old Atlas' 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's 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 Old Atlas 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's equity awards that have vested as of the date of termination would not be subject to forfeiture.
- upon termination by Old Atlas 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

Old Atlas' 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 Old Atlas; (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's equity awards.

When Mr. Jones's 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 Old Atlas 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.

"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" beginning on page 185. 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.

Eugene N. Dubay

2009 Employment Agreement

In January 2009, Old Atlas entered into an employment agreement with Eugene N. Dubay, who currently serves as Senior Vice President of Midstream and President and Chief Executive Officer of Atlas Pipeline GP. Mr. Dubay's employment agreement terminated in February 2011 in connection with the Chevron Merger, and Atlas Energy entered into a new employment agreement with Mr. Dubay on November 4, 2011. Old Atlas historically allocated all of Mr. Dubay's compensation cost to APL.

The agreement provided for an initial base salary of $400,000 per year and a bonus of not less than $300,000 for the period ending December 31, 2009. After that, bonuses would be awarded solely at the discretion of Old Atlas' compensation committee. In addition to reimbursement of reasonable and necessary expenses incurred in carrying out his duties, Mr. Dubay was entitled to reimbursement of up to $40,000 for relocation costs and Old Atlas agreed to purchase his residence in Michigan for $1,000,000. The agreement provided that if Mr. Dubay's employment was terminated before June 30, 2011 by him without good reason or by Old Atlas for cause, Mr. Dubay must repay an amount equal to the difference between the amount Old Atlas paid for his residence and its fair market value on the date acquired by Old Atlas. Upon execution of the agreement, Mr. Dubay was granted the following equity compensation:

- Options to purchase 100,000 shares of Old Atlas' common stock, which vest 25% per year on each anniversary of the effective date of the agreement;
- Options to purchase 100,000 of APL's common units, which vest 25% per year on each anniversary of the effective date of the agreement; and
- Options to purchase 100,000 of Atlas Energy's common units, which vest 25% on the third anniversary, and 75% on the fourth anniversary, of the effective date of the agreement.

The agreement had a term of two years and, until notice to the contrary, his term was automatically renewed for one year renewal terms. Old Atlas may terminate the agreement:

- at any time for cause;
- without cause upon 45 days' prior written notice;
- if he is physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and Atlas Energy's and APL's board of directors determine, in good faith based upon medical evidence, that he is unable to perform his duties; or
- in the event of Mr. Dubay's death.

Mr. Dubay had the right to terminate the agreement for good reason, including a change of control. Mr. Dubay must provide notice of a termination by him for good reason within 30 days of the event constituting good reason. Termination by Mr. Dubay for good reason was only effective if such failure has not been cured within 90 days after notice is given to Old Atlas. Mr. Dubay could also terminate the agreement without good reason upon 60 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:

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

"Good reason" is defined as any action or inaction that constitutes a material breach by Old Atlas 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 Old Atlas' voting securities or all or substantially all of Old Atlas' assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Old Atlas or Mr. Dubay or any member of his immediate family;
- Old Atlas consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction of Old Atlas other than with a related entity, in which either (a) Old Atlas' 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 Old Atlas directors immediately before the transaction and Old Atlas' Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) Old Atlas' voting securities immediately before the transaction represent less than 60% of the combined voting power immediately after the transaction of Old Atlas, 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 Old Atlas board members at the beginning of the period cease for any reason to constitute a majority of Old Atlas' board, unless the election or nomination for the election by Old Atlas' 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
- Old Atlas' shareholders approve a plan of complete liquidation or winding-up, or agreement of sale of all or substantially all of Old Atlas' assets or all or substantially all of the assets of its 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. Dubay's designated beneficiaries will 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 all such incentive compensation would be equal to the amount of incentive compensation Mr. Dubay earned during the prior fiscal year, pro-rated through the date of termination; and (c) any accrued but unpaid incentive compensation and vacation pay.
- Upon termination of employment by Old Atlas other than for cause, including disability, or by Mr. Dubay for good reason, if Mr. Dubay executes and does not revoke a release, Mr. Dubay will receive (a) pro-rated cash incentive compensation for the year of termination, based on actual performance for the year; and (b) monthly severance pay for the remainder of the employment term in

an amount equal to 1/12 of (x) his annual base salary and (y) the annual amount of cash incentive compensation paid to Mr. Dubay for the fiscal year prior to his year of termination; (c) monthly reimbursements of any COBRA premium paid by Mr. Dubay, less the monthly premium charge paid by employees for such coverage; and (d) automatic vesting of all equity awards.

- Upon Mr. Dubay's termination from employment by Old Atlas for cause or by Mr. Dubay for any reason other than good reason, Mr. Dubay will receive his accrued but unpaid base salary.

Mr. Dubay is also subject to a non-solicitation covenant for two years after any termination of employment and, in the event his employment is terminated by Old Atlas for cause, or terminated by him for any reason other than good reason, a non-competition covenant not to engage in any natural gas pipeline and/or processing business in the continental United States for 18 months.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. When Mr. Dubay's employment agreement terminated in February 2011, in connection with the Chevron Merger, he received the following, all of which was paid by Chevron: $4,182,865 for the cash-out of the Old Atlas equity he held and $879,712 in severance.

2011 Employment Agreement

On November 4, 2011, Atlas Energy entered into an employment agreement with Mr. Dubay. Under the agreement, Mr. Dubay has the title of Senior Vice-President of the Midstream Operations division of Atlas Energy's general partner. The agreement has an effective date of November 4, 2011 and has an initial term of two years, which automatically renews for successive one-year terms unless earlier terminated pursuant to the termination provisions of the agreement.

The agreement provides for an initial annual base salary of $500,000, and Mr. Dubay 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 executives generally.

The agreement provides the following benefits in the event of a termination of Mr. Dubay's employment:

- Upon a termination by Atlas Energy for cause or by Mr. Dubay without good reason, he is entitled to receive payment of accrued but unpaid base salary and (to the extent required to be paid under company policy) amounts of accrued but unpaid vacation, in each case through the date of termination (together, the "Accrued Obligations").
- Upon a termination of employment due to death or disability (defined as Mr. Dubay 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. Dubay accelerate and vest in full upon such termination ("Acceleration of Equity Vesting"), and Mr. Dubay or his estate is entitled to receive, in addition to payment of all Accrued Obligations, an amount equal to the bonus earned by him for the prior fiscal year multiplied by a fraction, the numerator of which is the number of days in the fiscal year in which his 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").
- 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 Mr. Dubay for good reason, he is entitled to either:
  - if he does not timely execute (or revokes) a release of claims against Atlas Energy, payment of the Accrued Obligations; or

- in addition to payment of the Accrued Obligations, if he timely executes and does not revoke a release of claims against Atlas Energy:
  - monthly cash severance installments each in an amount equal to one-twelfth of the sum of his then-current (i) annual base salary and (ii) the annual cash incentive bonus earned by him in respect of the fiscal year preceding the fiscal year in which his termination of employment occurs for the portion of the employment term remaining after the date of termination, payable for the then-remaining portion of the employment term (taking into account any applicable renewal term) assuming his termination had not occurred,
  - healthcare continuation at active employee rates for the then-remaining portion of the employment term (taking into account any applicable renewal term) assuming his termination had not occurred,
  - a prorated amount in respect of the bonus granted to him in respect of the fiscal year in which his termination of employment occurs based on actual performance for such year, calculated as the product of (x) the amount which would have been earned in respect of the award based on actual performance measured at the end of such fiscal year and (y) a fraction, the numerator of which is the number of days in such fiscal year through the date of termination, and the denominator of which is the total number of days in such fiscal year, paid in a lump sum in cash on the date payment would otherwise be made had he remained employed by Atlas Energy, and
  - Acceleration of Equity Vesting.

"Good reason" is defined under the agreement as:

- a material reduction in Mr. Dubay's base salary;
- a demotion from his position;
- a material reduction in Mr. Dubay'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 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. Dubay 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. Dubay has committed any demonstrable and material fraud;
- illegal or gross misconduct by Mr. Dubay that is willful and results in damage to Atlas Energy's business or reputation;
- Mr. Dubay is charged with a felony;
- Mr. Dubay fails to substantially perform his duties (other than as a result of disability) after written demand and a reasonable opportunity to cure; or
- Mr. Dubay 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. Dubay will be reduced such that the total payments to him which are subject to 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. Dubay 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	$ —	$ —	$2,151,000
Disability	—	—	2,151,000
Termination by Atlas Energy without cause or by Mr. Dubay for good reason	1,916,667[(3)]	31,634	2,151,000

(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" beginning on page 185. 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. Dubay's 2011 base salary, plus applicable bonus. Payments would be made in monthly installments for the remaining term of Mr. Dubay's employment agreement.

Eric T. Kalamaras

In September 2009, Old Atlas entered into a letter agreement with Eric Kalamaras, who served as Atlas Energy's Chief Financial Officer until February 2011 and served as the Chief Financial Officer of Atlas Pipeline GP until his resignation in October 2011. Old Atlas historically allocated all of Mr. Kalamaras' compensation cost to APL.

The agreement provided for an annual base salary of $250,000, a one-time cash signing bonus of $80,000 and a one-time award of 50,000 equity-indexed bonus units which entitled Mr. Kalamaras, upon vesting, to receive a cash payment equal to the fair market value of Atlas Energy's common units. Mr. Kalamaras exchanged the bonus units for phantom units, effective June 1, 2010, in connection with the approval of the 2010 APL Plan, which vest 25% per year.

Mr. Kalamaras was also eligible for discretionary annual bonus compensation in an amount not to exceed 100% of his annual base salary and participation in all employee benefit plans in effect during his employment. The agreement provided that Mr. Kalamaras would serve as an at-will employee.

The agreement provided the following regarding termination and termination benefits:

- Old Atlas may terminate Mr. Kalamaras' employment for any reason upon 30 days prior written notice, or immediately for cause.
- Mr. Kalamaras may terminate his employment for any reason upon 60 days prior written notice.
- Upon termination of employment for any reason, Mr. Kalamaras will receive his accrued but unpaid annual base salary through his date of termination and any accrued and unpaid vacation pay.

"Cause" is defined as having

- committed an act of malfeasance or wrongdoing affecting Old Atlas or its affiliates;
- breached any confidentiality, non-solicitation or non-competition covenant or employment agreement; or
- otherwise engaged in conduct that would warrant discharge from employment or service because of his negative effect on Old Atlas or its affiliates.

Mr. Kalamaras is also subject to a confidentiality and non-solicitation agreement for 12 months after any termination of employment. 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.

Upon Mr. Kalamaras's resignation in October 2011, he did not receive any payments other than accrued and unpaid vacation pay of $29,500. In addition, he forfeited all unvested equity awards.

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 Old Atlas 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 having a fair market value of $25,000, which upon vesting entitles the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. The phantom units vest over four years. In tandem with phantom unit grants, the Committee may grant a DER. The Committee determines the vesting period for phantom units. Phantom units granted under 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 having a market value of

$25,000, which, upon vesting, entitle the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. The phantom units 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.

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
Eugene N. Dubay	48,614(1)	—	3.24	1/15/2019	—	—
	—	100,000(4)	22.23	3/25/2021	80,000(5)	1,944,000
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
Eric Kalamaras	—	—	N/A	N/A	—	—
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) Represents options to purchase Atlas Energy's units, which vest as follows: 3/25/2014—25,000 and 3/25/2015—75,000.

(5) Represents Atlas Energy's phantom units, which vest as follows: 3/25/2014—20,000 and 3/25/2015—60,000.

(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

Name	Option Awards			Unit Awards			
	Number of Units Acquired on Exercise	Value Realized on Exercise ($)	Value from Cash Payout ($)	Number of Units Acquired on Vesting	Value Realized on Vesting ($)	Value from Cash Payout ($)	Total Value ($)
Edward E. Cohen	— (1)	—	57,398,850	195,514(2)	2,729,066	2,955,731	63,083,647
Eugene N. Dubay	126,386(3)	2,725,880	3,591,750	79,553(4)	2,253,781	591,116	9,394,494
Sean P. McGrath	— (5)	—	903,051	8,950	128,017	—	1,031,068
Eric Kalamaras	— (6)	—	316,350	22,000	752,125	—	1,068,475
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 Old Atlas 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 less the exercise price, which amount is shown in the "Value from Cash Payout" column.

(3) Pursuant to the terms of the Chevron Merger agreement, 145,000 Old Atlas 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.

(4) 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 less the exercise price, which amount is shown in the "Value from Cash Payout" column.

(5) Pursuant to the terms of the Chevron Merger agreement, 47,050 Old Atlas 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) Pursuant to the terms of the Chevron Merger agreement, 19,000 Old Atlas 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.

(7) Pursuant to the terms of the Chevron Merger agreement, 1,322,000 Old Atlas 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 less the exercise price, which amount is shown in the "Value from Cash Payout" column.

(9) Pursuant to the terms of the Chevron Merger agreement, 518,000 Old Atlas 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 less the exercise price, which amount is shown in the "Value from Cash Payout" column.

(11) Pursuant to the terms of the Chevron Merger agreement, 323,000 Old Atlas 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 less the exercise price, 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 Atlas Energy's $350,000 matching contribution in the All Other Compensation column.

(4) This amount is included within the Summary Compensation Table for 2011 reflecting Atlas Energy's $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.

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.

2011 Director Compensation Table

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	All Other Compensation ($)[1]	Total ($)
Carlton M. Arrendell	43,333	49,989[2]	1,790	95,112
William R. Bagnell	6,667	13,293[3]	218	20,178
Mark C. Biderman	43,333	49,989[2]	1,790	95,112
Dennis A. Holtz	47,667	49,989[2]	1,790	99,445
William Karis	54,333	49,979[4]	2,993	107,305
Jeffrey C. Key	6,667	—	327	6,994
Harvey Magarick	60,667	49,979[4]	2,993	113,638
Ellen F. Warren	52,000	49,989[2]	1,790	103,779

(1) Represents DERs for phantom units.

(2) For Messrs. Arrendell, Biderman, Holtz and Ms. Warren, represents 3,140 phantom units granted under Atlas Energy's Plans, having a grant date fair value of $15.92. The phantom units vest 25% on the anniversary of the date of grant as follows: 2/17/12—785, 2/17/13—785, 2/17/14—785 and 2/17/15—785.

(3) Represents 835 phantom units as a make-up grant for the underpayment of a 2009 phantom unit grant, having a grant date fair value of $15.92, granted under Atlas Energy's 2006 Plan. The phantom units vested on 2/17/11, upon Mr. Bagnell's departure.

(4) For Messrs. Karis and Magarick, represents 2,145 phantom units granted under Atlas Energy's Plans, having a grant date fair value of $23.30. The phantom units vest 25% on the anniversary of the date of grant as follows: 11/10/12—536, 11/10/13—536, 11/10/14—536 and 11/10/15—536.

Director Compensation

Atlas Energy's general partner does not pay additional remuneration to officers or employees of Atlas Energy who also serve as board members. In 2011, the annual retainer for non-employee directors was comprised of an annual retainer of $50,000 in cash and an annual grant of phantom units with DERs issued under Atlas Energy's Plans having a fair market value of $50,000. The new non-employee directors received a pro-rated portion of the cash retainer reflecting their mid-February appointment to the board. Chairs of the compensation committee and audit committee receive an additional retainer of $10,000, and chairs of the nominating and governance committee and the investment committee receive an additional retainer of $5,000.

SECURITY OWNERSHIP OF MANAGEMENT, DIRECTORS AND PRINCIPAL UNITHOLDERS

Before the separation and distribution, all of our outstanding common units, representing a 98% limited partner interest, will be owned beneficially and of record by Atlas Energy, and all of our outstanding class A units, representing a 2% general partner interest, will be owned beneficially and of record by Atlas Resource Partners GP, LLC, which is wholly owned by Atlas Energy. After the distribution, Atlas Energy will retain 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 will continue to own 100% of the equity of our general partner, Atlas Resource Partners GP, LLC, which, in turn, will own 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 expected beneficial ownership of our common units, immediately following the completion of the separation and distribution, by (1) each person who is known by us who will be beneficially own more than 5% of our common units, (2) each expected member of the board of directors of our general partner, (3) each executive officer named in the Summary Compensation Table, and (4) all of the executive officers and members of the board of directors of our general partner. Based on current publicly available information regarding beneficial ownership of Atlas Energy common units, we do not believe any person other than Atlas Energy will be a beneficial owner of more than 5% of our common units after the distribution. We based the number of units shown below on each person's beneficial ownership of Atlas Energy common units as of February 10, 2012, unless we indicate some other date or basis for the amounts in the applicable footnotes. The following table assumes that Atlas Energy distributes exactly 5,240,000 common units in the separation and distribution, and retains ownership of exactly 20,960,000 common units. The actual number of common units distributed, and the number of common units retained by Atlas Energy, will vary depending on the number of common units of Atlas Energy outstanding on the record date. 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. Following the distribution, we will have outstanding an aggregate of 26,200,000 common units.

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)]	20,960,000	80%	78.4%
Directors			
Edward E. Cohen	149,395[(2)]	*	*
Jonathan Z. Cohen	136,849[(3)]	*	*
Matthew A. Jones	3,273	*	*
Anthony Coniglio	0	*	*
DeAnn Craig	0	*	*
Jeffrey C. Key	0	*	*
Bruce Wolf	0	*	*
Non-Director Executive Officers			
Sean P. McGrath	1,070	*	*
Freddie M. Kotek	8,668[(4)]	*	*
Lisa Washington	334	*	*
All Executive Officers and Directors as a Group (10 persons)	299,589	1.14%	1.12%

* 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).

(4) Includes (i) 1,700 units held by Mr. Kotek and (ii) 6,968 units held as follows: 3,067 units held by Mrs. Beth Kotek (Mr. Kotek's spouse), 197 units held by Mr. Kotek's children, 255 units held by a trust for the benefit of Mr. Kotek's children and 659 units held by Rita Schnuldiner, the mother of Mrs. Kotek, and (iii) 2,789 units held in an employee stock ownership account. Mr. Kotek disclaims beneficial ownership of the units referenced in (ii) above.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Our Relationship with Atlas Energy and Atlas Resource Partners GP, LLC

Immediately following the separation and distribution, Atlas Energy will own 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 will own 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 of our general partner, and Edward Cohen, who serves as Chief Executive Officer and President of Atlas Energy and 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 will be held by Atlas Energy or one or more of its subsidiaries. In connection with the separation and distribution, we will enter into an agreement with Atlas Energy, pursuant to which Atlas Energy will agree 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.

Transfer of Assets and Assumption of Liabilities

The separation and distribution agreement will identify assets to be transferred, liabilities to be assumed and contracts to be assigned to us as part of our separation from Atlas Energy and will describe when and how these transfers, assumptions and assignments will occur. In particular, the separation and distribution agreement will generally provide 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 will also assume and be responsible for all liabilities and obligations related to these assets and businesses.

Atlas Energy will retain the following assets, which will not be 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 will also provide 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 will make any 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 will be transferred on an "as is," "where is" basis.

Assignment of Obligations

We and Atlas Energy will be required to use reasonable best efforts to obtain consents, approvals and amendments required to novate or assign the liabilities that are to be transferred pursuant to the separation and distribution agreement. If either party is unable to obtain required consents, approvals or amendments, the prospective assignor will act as agent or subcontractor for the prospective assignee and perform the assignee's obligations, and the assignee will pay and remit to the assignor all money, rights and other consideration received by the assignee in respect of such performance.

The Distribution

The separation and distribution agreement will also govern the rights and obligations of the parties regarding the proposed distribution of our common units to the Atlas Energy unitholders. Pursuant to the separation and distribution agreement, Atlas Energy will cause its agent to distribute 0.1021 of one of our common units for each Atlas Energy common unit held by such person as of the record date. Based on the number of outstanding Atlas Energy common units outstanding on the record date, we expect that approximately 5.24 million of our common units, representing an approximately 19.6% limited partner interest, will be distributed in the distribution.

In addition, the separation and distribution agreement will provide that the distribution is subject to several conditions that must be satisfied or waived by Atlas Energy in its sole discretion. For further information regarding these conditions, see the section entitled "The Separation and Distribution—Conditions to the Distribution" beginning on page 65. Atlas Energy may, in its sole discretion, determine the distribution date and the terms of the distribution, and may at any time until completion of the distribution decide to abandon or modify the distribution.

Termination

The separation and distribution agreement will provide that it may be terminated at any time prior to the distribution date by Atlas Energy.

Indemnification

We will indemnify 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.

Atlas Energy will indemnify 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.

The separation and distribution agreement will also specify procedures with respect to claims subject to indemnification and related matters.

Further Assurances

Atlas Energy and we will agree to use reasonable best efforts to take all actions reasonably necessary, proper or advisable to consummate and make effective the transactions contemplated by the separation and distribution agreement and any other agreement executed in connection therewith.

The separation and distribution agreement will be filed as an exhibit to the registration statement of which this document forms a part, and the summary sets forth the terms of the agreement that we believe are material. These summaries are qualified in their entireties by reference to the full text of the applicable agreements, which are incorporated by reference into this information statement. The terms of the agreements described above that will be in effect following the separation have not yet been finalized; changes to these agreements, some of which may be material, may be made prior to our separation from Atlas Energy.

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. See “Our Partnership Agreement—Indemnification” on page 217.

CONFLICTS OF INTEREST AND DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Atlas Energy and its affiliates), on the one hand, and us and our limited partners, on the other hand. Conflicts may arise as a result of the duties of our general partner to act for the benefit of its owners, which may conflict with our interests and the interests of our unitholders. The directors and officers of Atlas Energy have duties to manage Atlas Energy and our general partner in a manner beneficial to its owners. At the same time, our general partner has a contractual duty under our partnership agreement to manage us in good faith, defined as a belief that its decisions are not adverse to our interests. In addition, many of the officers and directors of our general partner serve in similar capacities with Atlas Energy and its affiliates, which may lead to additional conflicts of interest.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any other partner, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that eliminate any and all fiduciary duties under applicable law and replaces them with contractual standards as set forth therein. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without such elimination of any fiduciary duties, might constitute breaches of fiduciary duty by our general partner or its affiliates under applicable law.

Our general partner and its affiliates will not be in breach of any obligations under our partnership agreement or any duties to us or our unitholders if the resolution of a conflict is:

- approved by the conflicts committee of the board of directors of our general partner;
- approved by the vote of a majority of the holders of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors or from the common unitholders. The existence of all conflicts of interest described in this information statement, including from the transactions described in this information statement, and any actions of our general partner taken in connection with such conflicts of interest, will be deemed approved by all of our unitholders pursuant to our partnership agreement. If our general partner seeks approval by the conflicts committee of the board of directors of our general partner of any such action or resolution, it will be presumed that, in making its decision, the conflicts committee acted in good faith. If our general partner does not seek approval from the conflicts committee or from the common unitholders and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points 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. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factor it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to believe that he is not acting adversely to the interests of the partnership.

Conflicts of interest could arise in the situations described below, among others.

Atlas Energy is not limited in its ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our 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 acquire, develop or dispose of natural gas and oil properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. It may be difficult for us to compete with Atlas Energy and/or 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 cash available for distribution.

For example, Atlas Energy will retain 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 will also 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. Although we will also 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.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, shall not apply to Atlas Energy or any of its affiliates, including its executive officers and directors. No such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. Therefore, Atlas Energy and its affiliates may compete with us for investment opportunities and may own an interest in entities that compete with us on an operations basis.

Neither our partnership agreement nor any other agreement requires Atlas Energy to pursue a business strategy that favors us. Certain directors appointed by Atlas Energy have fiduciary duties to make these decisions in the best interests of the unitholders of Atlas Energy, which may be contrary to our interests.

Because certain of the directors of our general partner are also directors and/or officers of Atlas Energy or its affiliates, such directors have fiduciary duties to Atlas Energy that may cause them to pursue business strategies that disproportionately benefit Atlas Energy or that otherwise are not in our best interests.

Our general partner is allowed to take into account the interests of parties other than us in exercising certain rights under our partnership agreement.

Our partnership agreement contains provisions that eliminate the fiduciary standards that our general partner 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. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the allocation of business opportunities among us and its affiliates, exercise of its limited call right, exercise of its voting rights with respect to the units it owns, exercise of its registration rights, the determination of whether to reset target distribution levels and the determination of whether to consent to any merger or consolidation of the partnership or amendment of our partnership agreement.

We will not have any employees and will rely on the employees of Atlas Energy and its affiliates.

We will utilize a significant number of employees of Atlas Energy to operate our business and provide us with general and administrative services for which we will reimburse Atlas Energy for allocated expenses of personnel who perform services for our benefit, and we will reimburse Atlas Energy for allocated general and administrative expenses. Atlas Energy will also conduct businesses and activities of its own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the officers and employees who provide services to Atlas Energy. The officers of our general partner will not be required to work full time on our affairs. These officers may devote significant time to the affairs of Atlas Energy and will be compensated by Atlas Energy for services rendered to it. All of the officers of our general partner are also officers of Atlas Energy or its affiliates and will spend sufficient amounts of their time overseeing the management, operations, corporate development and future acquisition initiatives of our business.

Our general partner has limited its liability in the partnership agreement and eliminated default fiduciary duties and replaced them with contractual standards set forth therein, thereby restricting the remedies available to our unitholders for actions that, without such replacement, might constitute breaches of fiduciary duty.

In addition to the provisions described above, our partnership agreement contains provisions that restrict the remedies available to our unitholders for actions that might otherwise constitute breaches of fiduciary duty by our general partner or its affiliates. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to its capacity as general partner, thereby entitling our general partner to consider only the interests and factors that it desires, and imposes no duty or obligation on our general partner to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that the general partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decision was not adverse to our interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of common unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us, as determined by our general partner in good faith, and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be advantageous or beneficial to us;
- provides that our general partner 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 its officers or directors 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
- provides that in resolving conflicts of interest, it will be presumed that in making its decision, the general partner or its conflicts committee 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.

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

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought conflicts committee approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into our securities, and the incurring of any other obligations;
- the purchase, sale or other acquisition or disposition of our securities, or the issuance of additional options, rights, warrants, appreciation rights and tracking and phantom interests relating to our securities;
- the acquisition, disposition, mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets or the merger or other combination of us with or into another person;
- the use of our assets (including cash on hand) for any purpose consistent with the terms of our partnership agreement;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of our cash;
- the selection, employment, retention and dismissal of employees and agents, internal and outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;
- the maintenance of insurance for our benefit and the benefit of our partners;
- the formation of, or acquisition of an interest in, the contribution of property to and the making of loans to any further limited or general partnerships, joint ventures, corporations, limited liability companies or other entities;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity, otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the making of tax, regulatory and other filings, or the rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets;
- the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner; and
- the registering for resale under the applicable securities laws of any of our securities held or acquired by our general partner or any of its affiliates.

See "Our Partnership Agreement—Voting Rights" beginning on page 207 for information regarding matters that require unitholder approval.

Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- the manner in which our business is operated;
- the amount and timing of asset purchases and sales;
- the amount and timing of our capital expenditures;
- the amount of borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, estimates of which reduce operating surplus, or an expansion capital expenditure or investment capital expenditure, which do not reduce operating surplus. Please read "Cash Distribution Policy—Operating Surplus and Capital Surplus—Capital Expenditures" beginning on page 70 for a discussion on when a capital expenditure constitutes a maintenance capital expenditure, an expansion capital expenditure or an investment capital expenditure.

All of these actions may affect the amount of cash distributed to our unitholders and the general partner. Please read "Cash Distribution Policy" beginning on page 67 for more information on how we will make cash distributions.

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by the general partner to our unitholders, including borrowings that have the purpose or effect of enabling our general partner or its affiliates to receive distributions on any units held by them or the incentive distribution rights.

Our partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates, and our general partner and its affiliates may borrow funds from us or our affiliates.

Our general partner determines which costs incurred by it are reimbursable by us.

We will reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. Our partnership agreement will not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

Our partnership agreement does not restrict our general partner from causing us to pay it, Atlas Energy or their respective affiliates for any services rendered to us or from entering into additional contractual arrangements with any of these entities on our behalf.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us. Our general partner may also enter into additional contractual arrangements with Atlas Energy or any of their respective affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts or arrangements between us, on the one hand, and our general partner, Atlas Energy and their respective affiliates, on the other hand, that will be in effect as of the consummation of the distribution will be the result of arm's length negotiations. Similarly, agreements, contracts or arrangements between us and our general partner, Atlas Energy and their respective affiliates that are entered into following the consummation of the distribution will not be required to be negotiated on an arm's length basis, although, in some circumstances, our general partner may determine that the conflicts committee of our general partner may make a determination on our behalf with respect to such arrangements.

Our general partner will determine, in good faith, the terms of any of these related-party transactions entered into after the consummation of the distribution.

Our general partner and its affiliates will have no obligation to permit us to use any of their facilities or assets, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner or its affiliates to enter into any contracts of this kind.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our general partner may exercise its right to call and purchase common units if it and its affiliates own more than two-thirds of the common units.

Our general partner may exercise its right to call and purchase common units as provided in the partnership agreement or assign this right to one of its affiliates or to us. Our general partner is not bound by fiduciary duty restrictions in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read "Our Partnership Agreement—Limited Call Right" on page 215.

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us. Any agreements between us on the one hand, and our general partner, Atlas Energy and their respective affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner, Atlas Energy and their respective affiliates in our favor.

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

The attorneys, independent accountants and others who have performed services for us regarding the distribution have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other hand, depending on the nature of the conflict. We do not intend to do so in most cases.

No Fiduciary Duties

The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, restrict, expand or eliminate any fiduciary duties owed by general partners to other partners and the partnership. Our partnership agreement has eliminated any default fiduciary standards owed to the partnership or the other partners. Instead, our general partner, and its directors and officers, are accountable to us and our unitholders pursuant to the contractual standards set forth in our partnership agreement, which requires that, when the general partner is acting its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith," meaning that it believed that the decision was not adverse to our interests. Moreover, our partnership agreement provides that, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any duty or obligation to us or the unitholders whatsoever.

We have adopted these standards to allow our general partner, Atlas Energy or their affiliates to engage in transactions with us that could otherwise be prohibited by state law fiduciary standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because our general partner's board of directors has a duty to manage us in good faith and a duty to manage our general partner in a manner beneficial to its owner. Without these modifications, our general partner's ability to make decisions involving conflicts of interest could be restricted. These modifications also enable our general partner to take into consideration all parties involved in the proposed action. Further, these modifications also strengthen the ability of our general partner to attract and retain experienced and capable directors. However, these modifications disadvantage the common unitholders because they restrict the rights and remedies that would otherwise be available to unitholders for actions that, without such modifications, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest. The following is a summary of:

- the default fiduciary duties under the Delaware Act; and
- the standards contained in our partnership agreement that replace the default fiduciary duties.

State law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally require that any action taken or transaction engaged in be entirely fair to the partnership. The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These actions include actions against a general partner for breach of its fiduciary duties or of the partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of itself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.
Partnership agreement modified standards	Our partnership agreement has eliminated any default fiduciary standards owed to the partnership or the other partners. Instead, our general partner, and its directors and officers, are accountable to us and our unitholders pursuant to the contractual standards set forth in our partnership agreement, which requires that, when the general partner is acting its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith," meaning that it believed that the decision was not adverse to our interests. Moreover, our partnership agreement provides that, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any duty or obligation to us or the unitholders whatsoever. These contractual standards reduce the obligations to which our general partner would otherwise be held.

In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for errors of judgment or for any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that the general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such person's conduct was unlawful.

Special provisions regarding affiliated transactions. Our partnership agreement generally provides that, with respect to any transaction involving a conflict of interest or potential conflict of interest between us and our limited partners, on the one hand, and our general partner and its affiliates (including Atlas Energy and its affiliates), on the other hand, any action by our general partner with respect to such transaction 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:

- 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;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- 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.

The existence of all conflicts of interest disclosed in this information statement, and any actions of our general partner taken in connection with such conflicts of interest, have been approved by all of our unitholders pursuant to our partnership agreement.

If our general partner seeks approval by the conflicts committee of the board of directors of our general partner of any such action or resolution, it will be presumed that, in making its decision, the conflicts committee acted in good faith. 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 the third or fourth bullet 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. These standards reduce the obligations to which our general partner would otherwise be held.

By accepting or purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or transferee to sign a partnership agreement does not render our partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and its officers, directors, managers and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that these persons acted in bad faith or engaged in fraud or willful misconduct. We also must provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner or these other persons could be indemnified for their negligent and grossly negligent acts if they meet the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act, in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please read “Our Partnership Agreement—Indemnification” on page 217.

DESCRIPTION OF OUR COMMON UNITS

Common Units

The common units are a class of limited partner interests in us. The holders of common units are entitled to participate in partnership distributions and exercise the rights or privileges available to holder of common units as outlined in our partnership agreement. For a description of the rights and preferences of holders of common units in partnership distributions, please read this section and “Cash Distribution Policy” beginning on page 67. For a description of the rights and privileges of the holders of our common units under our partnership agreement, including voting rights, please read “Our Partnership Agreement” beginning on page 206.

Transfer Agent and Registrar

Duties. American Stock Transfer will serve as registrar and transfer agent for the common units. We will pay all fees charged by the transfer agent for transfers of common units except the following that must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There will be no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal. The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and has accepted the appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically becomes bound by the terms and conditions of, and is deemed to have executed, our partnership agreement;
- gives the consents and waivers contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and the distribution.

A transferee will become a limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records from time to time as necessary to accurately reflect the transfers.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder’s rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfers of securities.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

OUR PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement that will be in effect as of the distribution. The form of our partnership agreement is attached as Annex A to this information statement. We will provide holders of our common units with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this information statement:

- with regard to distributions of available cash, please read "Cash Distribution Policy" beginning on page 67;
- with regard to the duties of our general partner, please read "Conflicts of Interest and Duties" beginning on page 195;
- with regard to the transfer of common units, please read "Description of Our Common Units—Transfer of Common Units" beginning on page 204; and
- with regard to allocations of taxable income and taxable loss, please read "Certain U.S. Federal Income Tax Matters" beginning on page 220.

Organization and Duration

Our partnership was formed in October 2011 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under the partnership agreement is to engage in any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided, that our general partner shall not cause us to engage in any business activity that the general partner determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes.

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the production of natural gas and oil, our general partner has no current plans to do so and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. Our general partner is authorized in general to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Cash Distributions

Our partnership agreement specifies the manner in which we will make cash distributions to holders of our common units and other partnership securities as well as to our general partner in respect of its incentive distribution rights. For a description of these cash distribution provisions, please read "Cash Distribution Policy."

Capital Contributions; No Dilution of Class A Units; One-to-One Ratio Between Class A Units and Common Units

Unitholders are not obligated to make additional capital contributions, except as described below under "Our Partnership Agreement—Limited Liability" on page 209.

The class A units will be entitled to 2% of all distributions that we make prior to our liquidation. The 2% sharing ratio of the class A units will not be reduced if we issue additional equity securities in the future. Because the 2% sharing ratio will not be reduced if we issue additional equity securities, 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.

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a "unit majority" require the approval of a majority of the common units.

At the closing of the distribution, Atlas Energy will have the ability to ensure passage of, as well as the ability to ensure the defeat of, any amendment that requires a unit majority because Atlas Energy will hold approximately 80% of our outstanding common units.

In voting their common units, Atlas Energy and its affiliates will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. The holders of a majority of the common units represented in person or by proxy shall constitute a quorum at a meeting of such common unitholders, unless any such action requires approval by holders of a greater percentage of such units in which case the quorum shall be such greater percentage.

The following is a summary of the vote requirements specified for certain matters under our partnership agreement:

Issuance of additional partnership securities	No approval right. See "Our Partnership Agreement—Issuance of Additional Securities" beginning on page 209.
Amendment of our partnership agreement	Certain amendments may be made by our general partner without the approval of the common unitholders. Other amendments generally require the approval of a unit majority. See "Our Partnership Agreement—Amendment of the Partnership Agreement" beginning on page 210.
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. See "Our Partnership Agreement—Merger, Consolidation, Conversion, Sale or Other Disposition of Our Assets" beginning on page 212.
Dissolution of our partnership	Unit majority. See "Our Partnership Agreement—Termination and Dissolution" on page 213.
Continuation of our partnership upon dissolution	Unit majority. See "Our Partnership Agreement—Termination and Dissolution" on page 213.
Withdrawal of our general partner	Prior to the tenth anniversary of the date of the distribution, under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner in a manner that would cause a dissolution of our partnership. See "Our Partnership Agreement—Withdrawal or Removal of Our General Partner" beginning on page 213.

Removal of our general partner	Not less than two-thirds of the outstanding common units, including common units held by our general partner and its affiliates. See "Our Partnership Agreement—Withdrawal or Removal of Our General Partner" beginning on page 213.
Transfer of the general partner interest	Our general partner may transfer without a vote of our common unitholders all, but not less than all, of its general partner interest in us to an affiliate or another person (other than an individual) in connection with its merger or consolidation with or into, or sale of all, or substantially all, of its assets, to such person. The approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required in other circumstances for a transfer of the general partner interest to a third-party prior to the tenth anniversary of the date of the distribution. See "Our Partnership Agreement—Transfer of General Partner Interest" beginning on page 214.
Transfer of ownership interests in our general partner	No approval required at any time. See "Our Partnership Agreement—Transfer of Ownership Interests in the General Partner" on page 215.

The holder of our class A units has all voting rights applicable to the general partner.

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that, unless we (through the approval of our general partner) consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall be the sole and exclusive forum for any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine;

regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. However, if and only if the Court of Chancery of the Statement of Delaware dismisses any such claims, suits, actions or proceedings for lack of subject matter jurisdiction, such claims, suits, actions or proceedings may be brought in another state or federal court sitting in the State of Delaware. By acquiring or purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware in connection with any such claims, suits, actions or proceedings.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and otherwise acts in conformity with the provisions of our partnership agreement, the limited partner's liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner,
- to approve some amendments to our partnership agreement, or
- to take other action under our partnership agreement

constituted "participation in the control" of our business for purposes of the Delaware Act, then our limited partners could be held personally liable for our obligations under Delaware law to the same extent as our general partner. This liability would extend to persons who transact business with us and reasonably believe that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership cannot make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. Moreover, under the Delaware Act, a limited partnership may also not make a distribution to a partner upon the winding up of the limited partnership before liabilities of the limited partnership to creditors have been satisfied by payment or the making of reasonable provision for payment thereof. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act will be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, an assignee who becomes a limited partner is liable for the obligations of his assignor to make contributions to the partnership, except such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

We currently conduct business in Colorado, Indiana, Michigan, New York, Ohio, Pennsylvania, Tennessee and West Virginia. Limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established in many jurisdictions. If it were determined that we were conducting business in any state without compliance with the applicable limited partnership statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by our general partner without the approval of our unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership securities may dilute the value of the interests of the then-existing holders of common units in our net assets. The holders of common units will not have preemptive rights to acquire additional common units or other partnership securities.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to our common units.

The class A units will be entitled to 2% of all distributions that we make prior to our liquidation. The 2% sharing ratio of the class A units will not be reduced if we issue additional equity securities in the future. Because the 2% sharing ratio will not be reduced if we issue additional equity securities, 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 to the right to receive additional class A units, our general partner will have a limited preemptive right in connection with any issuance by us of additional partnership securities. The right, which the general partner may assign in whole or in part to any of its affiliates, will entitle the general partner to purchase additional units of any securities being sold to third parties, on the same terms as such third parties, in an amount up to the amount necessary to maintain the aggregate ownership percentage of the general partner and its affiliates at the same level before and after such issuance.

Amendment of the Partnership Agreement

General. Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners. To adopt a proposed amendment, other than the amendments discussed under "Our Partnership Agreement—Amendment of the Partnership Agreement—No Unitholder Approval" beginning on page 211, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment.

Prohibited Amendments. No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option.

The provision of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class.

No Unitholder Approval. Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate for us to qualify us or continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that we will not be taxed as a corporation or otherwise taxed as an entity for U.S. federal income tax purposes;
- a change in our fiscal year or taxable year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner, or its directors, officers, agents or trustees, from in any manner being subject to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940 or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary or appropriate for the authorization or issuance of additional partnership securities or options, warrants, rights or appreciation rights relating to any partnership securities;
- an amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- any amendment effected, necessitated or contemplated by a merger agreement or plan of conversion that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;
- any amendment necessary to require our limited partners to provide a statement, certification or other evidence to us regarding whether such limited partner is subject to U.S. federal income taxation on the income generated by us or regarding such limited partner's nationality or citizenship and to provide for the ability of our general partner to redeem the units of any limited partner who fails to provide such statement, certification or other evidence;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; and
- any other amendment substantially similar to any of the matters described above.

In addition, our general partner may amend our partnership agreement, without the approval of the unitholders, if our general partner determines that those amendments:

- do not adversely affect the limited partners in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange or interdealer quotation system on which the limited partner interests are or will be listed for trading;

- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units or to implement the tax-related provisions of our partnership agreement; or
- are required to effect the intent expressed in this registration statement or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Unitholder Approval. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to our limited partners or result in our being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding common units if our general partner determines that such amendment will affect the limited liability of any limited partner under Delaware law.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding common units constitute not less than the voting requirement sought to be reduced. Any amendment that would increase the percentage of common units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding common units constitute not less than the percentage sought to be increased.

Merger, Consolidation, Conversion, Sale or Other Disposition of Our Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or any other standard imposed by our partnership agreement, the Delaware Act or applicable law.

In addition, the partnership agreement generally prohibits our general partner, without the prior approval by a unit majority, from causing us to sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without the approval of a unit majority. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger, consolidation or conversion without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction will not result in an amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction and the number of partnership securities to be issued does not exceed 20% of our outstanding partnership securities immediately prior to the transaction.

If the conditions specified in the partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the purpose of that conversion, merger or conveyance is to effect a change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters and the general partner determines that the governing instruments of the new entity provide the limited partners and the general partner with substantially the same rights and obligations as contained in the partnership agreement. The unitholders are not entitled to dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until dissolved under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by a unit majority;
- the entry of a decree of judicial dissolution of our partnership;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in us in accordance with our partnership agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last item above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of a unit majority subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and
- neither our partnership nor any of our subsidiaries would be taxed as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a new limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate liquidate our assets and apply the proceeds of the liquidation as described in "Cash Distribution Policy." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to the tenth anniversary of the date of the distribution, without obtaining the approval of the holders of at least a majority of our outstanding common units, excluding common units held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after the tenth anniversary of the date of the distribution, our general partner may withdraw as our general partner without first obtaining approval from the unitholders by giving 90 days' written notice. Notwithstanding the information above, our general partner may withdraw as our general partner without unitholder approval upon 90 days' notice to our limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates. In addition, our partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. See "Our Partnership Agreement—Transfer of General Partner Interest" beginning on page 214.

If our general partner withdraws, other than as a result of a transfer of all or a part of its general partner interest in us, the holders of a unit majority may elect a successor to the withdrawing general partner. If a successor is not elected prior to the effective date of the withdrawal, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved and liquidated, unless within a specified period of time after that withdrawal, the holders of a unit majority elect to continue the partnership by appointing a successor general partner. See "Our Partnership Agreement—Termination and Dissolution" on page 213.

Our general partner may not be removed unless that removal is approved by the vote of the holders of at least 66-⅔% of the outstanding units, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a unit majority, including units held by our general partner and its affiliates. The ownership of more than 33-⅓% of our outstanding common units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal. At the closing of this distribution, Atlas Energy will own 80% of our outstanding common units.

In the event of removal of our general partner under circumstances where cause exists or a withdrawal of our general partner that violates our partnership agreement, a successor general partner will have the option to purchase the class A units and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed, the departing general partner will have the option to require the successor general partner to purchase those interests for their fair market value. In each case, fair market value will be determined by agreement between the departing general partner and the successor general partner. If they cannot reach an agreement, an independent expert selected by the departing general partner and the successor general partner will determine the fair market value. If the departing general partner and the successor general partner cannot agree on an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the purchase option is not exercised by either the departing general partner or the successor general partner, the class A units and incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Except for the transfer by our general partner of all, but not less than all, of its class A units to:

- an affiliate of our general partner (other than an individual); or
- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity,

our general partner may not transfer all or any part of its general partner interest to another person, prior to the tenth anniversary of the date of the distribution, without the approval of the holders of at least a majority of our outstanding common units, excluding common units held by our general partner and its affiliates. As a condition of this transfer, the transferee must assume, among other things, the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates may at any time transfer common units to one or more persons without unitholder approval.

Transfer of Ownership Interests in the General Partner

The members of our general partner may sell or transfer all or part of their interest in our general partner without the approval of the unitholders.

Transfer of Incentive Distribution Rights

Our general partner or any other holder of incentive distribution rights may transfer any or all of its incentive distribution rights without unitholder approval.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Atlas Resource Partners GP, LLC as our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of our common units, that person or group will lose voting rights on all of its units and the common units will not be considered outstanding for the purposes of noticing meetings, determining the presence of a quorum, calculating required votes and other similar matters. This loss of voting rights does not apply to any person or group that acquires the common units from our general partner or its affiliates, any transferees of that person or group approved by our general partner or any person or group who acquires the common units directly from us if our general partner notifies such person or group in writing, in advance, that this limitation will not apply.

Limited Call Right

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 as of a record date selected by our general partner on at least 10 but not more than 60 days' notice.

The purchase price is the greater of:

- 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
- 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 the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The federal income tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Meetings; Voting

Except as described above under "Our Partnership Agreement—Change of Management Provisions" on page 215, unitholders who are record holders of common units on a record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited. Our general partner does not anticipate that any meeting of common unitholders will be called in the foreseeable future.

Any action that is required or permitted to be taken by the common unitholders may be taken either at a meeting of the common unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of common units necessary to authorize or take that action at a meeting. Meetings of the common unitholders may be called by our general partner or by holders of at least 20% of the outstanding common units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding common units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the common units, in which case the quorum will be the greater percentage.

Except as described above under "Our Partnership Agreement—Change of Management Provisions" on page 215, each record holder will have a vote in accordance with his percentage interest, although additional limited partner interests having different voting rights could be issued. See "Our Partnership Agreement—Issuance of Additional Securities" beginning on page 209. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner.

Any notice, demand, request report, or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

By transfer of any common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described above under "Our Partnership Agreement—Limited Liability" beginning on page 209, the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Assignees; Redemption

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, we may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, 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 this information within 30 days 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, then 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.

In addition, in such circumstance, we will have the right to acquire all (but not less than all) of the units held by such limited partner or non-citizen assignee. The purchase price for such units will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for such purchase, and such purchase price will be paid (in the sole discretion of our general partner) either in cash or by delivery of a promissory note. Any such promissory note will bear interest at the rate of 5% annually and will be payable in three equal annual installments of principal and accrued interest, commencing one year after the purchase date.

Non-Taxpaying Holders; Redemption

If our general partner, with the advice of counsel, 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 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 necessary or advisable 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 at their current market price held by any person whose tax status has or is reasonably likely to have a material adverse effect on our ability to operate our assets or generate revenues from our assets or who fails to comply with the procedures instituted by our general partner to obtain proof of the U.S. federal income tax status.

A non-taxpaying assignee does not have the right to direct the voting of his units and may not receive distributions in-kind upon our liquidation.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, by reason of their status as such, 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:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a manager, managing member, officer, director, employee, agent, fiduciary or trustee of our partnership, our subsidiaries, our general partner, any departing general partner or any affiliate of our partnership, our subsidiaries, our general partner, any departing general partner;
- any person who is or was serving at the request of a general partner or any departing general partner or any affiliate of a general partner or any departing general partner as a manager, managing member officer, director, employee, agent, fiduciary or trustee of another person; and
- any person whom the general partner designates as an indemnitee for purposes of our partnership agreement.

Our indemnification obligation arises only if the indemnified person did not act in bad faith or engage in fraud, willful misconduct or, in the case of a criminal matter, knowledge of the indemnified person's unlawful conduct.

Any indemnification under these provisions will be only out of our assets. Our general partner will not be personally liable for the indemnification obligations and will not have any obligation to contribute or loan funds to us in connection with it. Our partnership agreement permits us to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under the partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf, and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us, and our partnership agreement does not place any aggregate limit on the amount of such reimbursements.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For financial and tax reporting purposes, our fiscal year end is December 31.

We will furnish or make available to record holders of common units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent registered public accounting firm. Except for our fourth quarter, we also furnish or make available summary financial information within 90 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website that we maintain.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on the cooperation of our unitholders in supplying us with specific information. Every unitholder will receive information to assist it in determining its federal and state tax liability and filing its federal and state income tax returns, regardless of whether it supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to its interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, obtain:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each became a partner;
- copies of our partnership agreement, the certificate of limited partnership and related amendments and powers of attorney under which they have been executed; and
- information regarding the status of our business and financial condition.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes is not in our best interests or which we are required by law or by agreements with third parties to keep confidential.

Registration Rights

In 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.

CREDIT AGREEMENT

Simultaneously with or prior to the closing of the separation and distribution, we anticipate entering into a senior secured revolving credit facility, which we refer to as the credit facility, with an initial borrowing base of $138 million, and have received commitments from a group of lenders with respect to such a facility. The anticipated maturity of the credit facility is March 2016. We anticipate that the credit facility will allow us to borrow up to the lesser of the total commitments and the determined amount of the borrowing base, which will be based upon the loan collateral value assigned to our various natural gas and oil properties and other assets. We anticipate that the credit facility will also provide for the issuance of letters of credit, which would reduce our borrowing capacity. The borrowing base under the credit facility will be redetermined semi-annually, with additional interim re-determinations permitted under certain circumstances. In connection with each redetermination of the borrowing base, the administrative agent for the credit facility will propose a new borrowing base based upon, among other things, reserve reports and such other information as they deem appropriate in their reasonable discretion and consistent with its normal oil and natural gas lending criteria as they exist at the applicable time. The new proposed borrowing base will require the approval of the lenders. If at any time the amount of loans and other extensions of credit outstanding under the credit facility exceed the borrowing base, we may be required, among other things, to prepay loans under the credit facility and/or mortgage additional oil and gas properties. The borrowing base will be automatically reduced upon the occurrence of certain events, including the issuance of senior notes by us and certain sales of oil and gas properties. Our obligations under the credit facility will be secured by mortgages on our oil and gas priorities and first priority security interests in substantially all of our assets, including our ownership interests in a majority of our material operating subsidiaries. Additionally, our obligations under the credit facility will be guaranteed by certain of our material subsidiaries.

At our election, interest on borrowings under the credit facility will be determined by reference to either LIBOR plus an applicable margin between 2.00% and 3.25% per annum or the “alternate base rate” plus an applicable margin between 1.00% and 2.25% per annum. These margins will fluctuate based on the utilization of the credit facility. Interest will generally be payable quarterly for loans bearing interest based on the alternative base rate and at the applicable maturity date for LIBOR-based loans. We will be required to pay a fee of 0.5% per annum on the unused portion of the borrowing base under the credit facility. Borrowings under the credit facility will be available for, among other things, working capital and general corporate purposes.

The credit facility will contain customary covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency exists or a default under the credit facility exists or would result from the distribution, merger into or consolidation 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 our assets. The credit facility will also contain covenants that require us to maintain certain financial ratios.

CERTAIN U.S. FEDERAL INCOME TAX MATTERS

Overview

The following is a summary of certain U.S. federal income tax consequences to U.S. holders (as defined below) relating to the distribution of our common units by Atlas Energy and the ownership and disposition of our common units. This summary is based on the Internal Revenue Code of 1986, as amended (the "Code"), the U.S. Treasury regulations promulgated thereunder, and interpretations of the Code and the U.S. Treasury regulations by the courts and the Internal Revenue Service (the "IRS"), in effect as of the date hereof, all of which are subject to change, possibly with retroactive effect. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Atlas Resource Partners, L.P.

This summary addresses the material U.S. federal income tax consequences only to an individual citizen or resident of the United States who is a beneficial owner for U.S. federal income tax purposes of (i) our common units and, (ii) solely with respect to the discussion under the heading "Certain U.S. Federal Income Tax Matters—Tax Consequences of the Distribution of Our Common Units by Atlas Energy" beginning on page 222, common units of Atlas Energy (a "U.S. holder"). In addition, this summary is limited to U.S. holders who receive our common units in the distribution in their capacity as partners of Atlas Energy, and who hold such units and their common units of Atlas Energy as a capital asset for U.S. federal income tax purposes. In addition, this summary does not discuss all the tax considerations that may be relevant to unitholders in light of their particular circumstances, nor does it address the consequences to unitholders subject to special treatment under the U.S. federal income tax laws (including, for example, unitholders other than U.S. holders, insurance companies, dealers or brokers in securities or currencies, tax-exempt organizations, banks, financial institutions, mutual funds, real estate investment trusts, individual retirement accounts, pass-through entities and investors in such entities, unitholders who have a functional currency other than the U.S. dollar, unitholders who hold their units as a hedge or as part of a hedging, straddle, conversion, synthetic security, integrated investment or other risk-reduction transaction, unitholders who are subject to alternative minimum tax, unitholders who acquired their units as compensation or otherwise in connection with compensation arrangements, unitholders who hold (directly, indirectly or constructively) units representing 5% or more of our capital or profit or the capital or profit of Atlas Energy, or unitholders who acquired their units of Atlas Energy in exchange for a contribution of property described in Section 704(c) of the Code).

Furthermore, this summary does not address any U.S. federal taxes other than U.S. federal income tax, and does not discuss any state, local or foreign tax consequences. Nor does this summary discuss any tax consequences of the Medicare tax on certain investment income pursuant to the recently enacted Health Care and Education Reconciliation Act of 2010. Each unitholder is urged to consult its tax advisor regarding the U.S. federal, state, local and foreign tax considerations of the distribution and the ownership and disposition of our common units.

No ruling has been or will be requested from the IRS regarding any matter affecting us or unitholders. Accordingly, the U.S. federal income tax consequences described in this summary may be contested by the IRS and sustained by a court. Any contest of this sort with the IRS may materially and adversely impact the market for our common units and the prices at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of the distribution, our operations, and an investment in us may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

This summary of U.S. federal income tax consequences is for general information purposes. This summary does not purport to address all U.S. federal income tax consequences that may be relevant to

unitholders in light of their particular circumstances, nor does it address any state, local or foreign tax consequences. Unitholders are urged to consult their own advisors concerning the U.S. federal, state, local and foreign tax consequences to them of the distribution and of the ownership and disposition of our common units.

Partnership Status

In general, a partnership is a pass-through entity and incurs no U.S. federal income tax liability. Instead, each partner of a partnership is required to take into account such partner's share of items of income, gain, loss and deduction of the partnership in computing such partner's U.S. federal income tax liability, regardless of whether cash distributions are made to such partner by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in such partner's partnership interest.

Section 7704 of the Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations for U.S. federal income tax purposes. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income.

Based on estimates of our current gross income, we believe that at least 90% of such income constitutes qualifying income and, thus, we believe that we will be classified as a partnership for U.S. federal income tax purposes under the Qualifying Income Exception to Section 7704 of the Code. Similarly, based on estimates of the current gross income of Atlas Energy, we and Atlas Energy believe that at least 90% of such income of Atlas Energy constitutes qualifying income, and thus, we and Atlas Energy believe that Atlas Energy will be classified as a partnership for U.S. federal income tax purposes on the date of the distribution under the Qualifying Income Exception to Section 7704 of the Code. In addition, Atlas Energy files U.S. federal income tax returns on the basis that it should be classified as a partnership for U.S. federal income tax purposes. However, the portion of our or Atlas Energy's income that is qualifying income may change from time to time, and no assurance can be given that at least 90% of our or Atlas Energy's current or future gross income will constitute qualifying income.

No ruling has been or will be sought from the IRS, nor has the IRS has made any determination as to our or Atlas Energy's status for U.S. federal income tax purposes or whether our or Atlas Energy's operations generate qualifying income under Section 7704 of the Code. The IRS could assert that we or Atlas Energy should be treated as a corporation for U.S. federal income tax purposes, either as a result of a failure to meet the Qualifying Income Exception or otherwise. If we or Atlas Energy fail to meet the Qualifying Income Exception under Section 7704 of the Code, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we or Atlas Energy, as applicable, will be treated as if we or Atlas Energy, as applicable, had transferred all of our assets or Atlas Energy's assets, as applicable, subject to liabilities, to a newly formed corporation on the first day of the year in which we or Atlas Energy, as applicable, fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us or Atlas Energy, as applicable. This contribution and liquidation should be tax-free to unitholders and us or Atlas Energy, as applicable, so long as we or Atlas Energy, as applicable, at that time, do not have liabilities in excess of the tax basis of our assets or Atlas Energy's assets, as applicable. Thereafter, we or Atlas Energy, as applicable, would be treated as a corporation for U.S. federal income tax purposes.

If Atlas Energy were taxable as a corporation for U.S. federal income tax purposes on the date of the distribution, either as a result of a failure to meet the Qualifying Income Exception or otherwise, materially adverse consequences could result to Atlas Energy and unitholders of Atlas Energy who receive our common units in the distribution. If Atlas Energy were taxable as a corporation for U.S. federal income tax purposes on the date of the distribution, Atlas Energy would be subject to tax on gain, if any, that it would have recognized if it had sold the common units received by unitholders of Atlas Energy in the distribution in a taxable sale for their fair market value. In addition, in such case, each unitholder of Atlas Energy who receives our common units in the distribution would be treated as if the unitholder had received a distribution equal to the fair market value of our common units that were distributed to the unitholder, which generally would be treated as either taxable dividend income to the unitholder, to the extent of Atlas Energy's current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in such unitholder's units of Atlas Energy, or taxable capital gain, after the unitholder's tax basis in such unitholder's units of Atlas Energy is reduced to zero. Accordingly, taxation of Atlas Energy as a corporation on the date of the distribution could result in materially adverse tax consequences to Atlas Energy and unitholders of Atlas Energy who receive our common units in the distribution.

If we were taxable as a corporation for U.S. federal income tax purposes in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, the unitholders will be subject to special tax rules and materially adverse consequences could result to unitholders and us. If we were a taxable corporation for U.S. federal income tax purposes, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates, currently at a maximum rate of 35%. In addition, in such case, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in such unitholders common units in us, or taxable capital gain, after the unitholder's tax basis in such unitholder's common units in us is reduced to zero. Accordingly, taxation of us as a corporation could result in materially adverse tax consequences, as well as a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of our units.

The discussion below assumes that we and Atlas Energy will each be classified as a partnership for U.S. federal income tax purposes.

Tax Consequences of the Distribution of Our Common Units by Atlas Energy

Recognition of Gain

While not free from doubt due to the absence of controlling legal authority, we believe that the distribution of our common units by Atlas Energy to a U.S. holder of common units of Atlas Energy should not be taxable to such U.S. holder for U.S. federal income tax purposes, except to the extent that the aggregate amount of money distributed (including cash received in lieu of fractional units) or deemed distributed to such U.S. holder (as discussed below) exceeds such U.S. holder's tax basis in such U.S. holder's common units of Atlas Energy immediately before the distribution. In general, any money distributed or deemed distributed (as described below) to such U.S. holder in excess of such U.S. holder's tax basis should be considered to be gain from the sale or exchange of such U.S. holder's common units of Atlas Energy, taxable in accordance with the rules described below under "Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units" beginning on page 234. No loss shall be recognized for U.S. federal income tax purposes by a U.S. holder on such distribution.

For purposes of determining whether gain is recognized by a U.S. holder on such distribution of our common units, the distribution of a "marketable security" generally is treated as a distribution of money equal to the fair market value of such marketable security on the date of the distribution. In general, a "marketable security" includes a financial instrument (including stock or other equity interest) which is, as of the date of the distribution, "actively traded" for U.S. federal income tax purposes. The amount treated as money upon a distribution of a "marketable security" is reduced (but not below zero) by the excess, if any, of the distributee

U.S. holder's proportionate share of (i) net gain, if any, that would be recognized if all of Atlas Energy's marketable securities would have been sold immediately before the distribution by Atlas Energy for fair market value, over (ii) net gain, if any, that would be recognized if all of Atlas Energy's marketable securities would have been sold immediately after the distribution by Atlas Energy for that same fair market value, in each case with certain adjustments pursuant to U.S. Treasury regulations (including taking into account the U.S. holder's basis adjustment, if any in such marketable securities by reason of an election under Section 754 of the Code). Because we have applied to list our common units on the NYSE, we and Atlas Energy believe, and intend to take the position that our common units distributed by Atlas Energy in the distribution are "actively traded" on the date of the distribution and thus "marketable securities." Therefore, subject to the reduction described above, we believe our common units distributed by Atlas Energy should be treated as money for purposes of determining whether the U.S. holder recognizes gain for U.S. federal income tax purposes on the distribution of our common units by Atlas Energy in the distribution.

Any reduction in the U.S. holder's share of liabilities of Atlas Energy for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," generally will be treated as a deemed distribution of money to such U.S. holder for U.S. federal income tax purposes. For purposes of determining a U.S. holder's share of liabilities of Atlas Energy, U.S. Treasury regulations provide that an upper-tier partnership's share of the liabilities of a lower-tier partnership (other than any liability of the lower-tier partnership that is owed to the upper-tier partnership) generally should be treated as a liability of the upper-tier partnership. Furthermore, U.S. Treasury regulations provide that if, as a result of a single transaction, a partner incurs both an increase in the partner's share of the partnership liabilities and a decrease in the partner's share of the partnership liabilities, only the net decrease is treated as a distribution from the partnership and only the net increase is treated as a contribution of money to the partnership. While not free from doubt due to the absence of controlling legal authority, we believe that under these U.S. Treasury regulations the increase and decrease, if any, in the U.S. holder's liabilities of Atlas Energy and us solely by reason of the pro rata distribution by Atlas Energy of our common units in the distribution should be netted to equal zero so that there will be no deemed contribution or distribution of money by a U.S. holder with respect to such increase or decrease of liabilities solely by reason of the distribution.

To the extent the distribution causes the "at risk" amount of U.S. holder of common units in Atlas Energy to be less than zero at the end of any taxable year, such U.S. holder must recapture any losses deducted in previous years. Unitholders are urged to consult their own tax advisors with respect to the "at risk" rules in their particular circumstances and read the summary under the heading entitled "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Limitations on Deductibility of Losses" beginning on page 226.

Atlas Energy expects to provide unitholders with information regarding the amount deemed to be treated as money upon the distribution of our common units.

Basis and Holding Period

A U.S. holder's initial basis in our common units received by such U.S. holder in the distribution generally will be equal to Atlas Energy's adjusted basis in such common units immediately before the distribution. However, such U.S. holder's initial basis in such common units shall not exceed the adjusted basis of such U.S. holder's interest in Atlas Energy common units, reduced by any money distributed in the same transaction. In addition, such U.S. holder's initial basis in such common units shall be increased by the amount of any gain such U.S. holder recognizes on the distribution of "marketable securities" as described above. Furthermore, if such U.S. holder acquired any part of such U.S. holder's interest in Atlas Energy in a transfer as to which an election under Section 754 of the Code was in effect, then Atlas Energy's adjusted basis in our common units distributed to such U.S. holder generally should take into account such U.S. holder's special basis adjustment, if any, in such common units.

A U.S. holder's adjusted basis in such U.S. holder's interest in Atlas Energy generally will be reduced (but not below zero) by the amount of money distributed by Atlas Energy to such U.S. holder and such U.S. holder's initial basis in our common units distributed by Atlas Energy to such U.S. holder in the distribution, determined as if no gain were recognized by the U.S. holder as a result of our common units being treated as "marketable securities" as described above.

A U.S. holder's holding period for our common units distributed by Atlas Energy to such U.S. holder in the distribution generally will include Atlas Energy's holding period for those common units.

Atlas Energy expects to provide unitholders with information regarding its adjusted basis and holding period in our common units distributed by Atlas Energy to its unitholders in the distribution.

The rules governing the U.S. federal income tax consequences of the distribution of our common units by Atlas Energy in the distribution are complex. Unitholders are urged to consult their own tax advisors regarding the application of these rules and the U.S. federal income tax consequences of the distribution to them in their particular circumstances.

Tax Consequences of Ownership of Our Common Units

Limited Partner Status

Unitholders who have been admitted as limited partners of us will be treated as partners of us for U.S. federal income tax purposes. Also, assignees who have executed and delivered transfer applications, and are awaiting admission as limited partners, and unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of us for U.S. federal income tax purposes.

There is no direct authority addressing assignees of units who are entitled to execute and deliver transfer applications and thereby become entitled to direct the exercise of attendant rights, but who fail to execute and deliver transfer applications. Furthermore, a purchaser or other transferee of units who does not execute and deliver a transfer application may not receive some U.S. federal income tax information or reports furnished to record holders of units unless the units are held in a nominee or street name account and the nominee or broker has executed and delivered a transfer application for those units. In addition, a beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes, as discussed further under the section entitled "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Treatment of Short Sales" beginning on page 228.

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for U.S. federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for U.S. federal income tax purposes would therefore appear to be fully taxable as ordinary income. Unitholders are urged to consult their own tax advisors with respect to their status as partners in us for U.S. federal income tax purposes.

This summary assumes that holders of our common units are partners for U.S. federal income tax consequences. Further, the references to "unitholders" and "U.S. holder" in this summary are to persons who are treated as partners for U.S. federal income tax purposes.

Flow-Through of Taxable Income

In general, we are a pass-through entity and will incur no U.S. federal income tax liability. Instead, each unitholders will be required to take into account and report on such unitholder's income tax return such unitholder's share of our items of income, gain, loss and deduction in computing such unitholder's U.S. federal income tax liability, regardless of whether we make corresponding cash distributions to such unitholder. Consequently, we may allocate income to a unitholder even if such unitholder has not received a cash distribution. Each unitholder will be required to include in income such unitholder's allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Distributions

Distributions by us to a unitholder generally will not be taxable to the unitholder for U.S. federal income tax purposes, except to the extent that any money (and certain "marketable securities") distributed by us to such unitholder exceeds such unitholder's adjusted basis in our common units immediately before the distribution. Our distributions of money in excess of a unitholder's adjusted basis generally will be considered to be gain from the sale or exchange of our common units, taxable in accordance with the rules described under "Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units" beginning on page 234. Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Limitations on Deductibility of Losses" beginning on page 226.

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease such unitholder's share of our "non-recourse liabilities," and thus will result in a corresponding deemed distribution of money. A non-pro rata distribution of money or other property may result in ordinary income to a unitholder, regardless of such unitholder's adjusted basis in our common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, and/or substantially appreciated "inventory items," both as defined in the Code, and collectively, "Section 751 Assets." To that extent, the unitholder generally will be treated as having been distributed such unitholder's proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's adjusted basis for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions

We estimate that a U.S. Holder who receives our common units in the distribution and holds such common units from the distribution date through the record date for distributions for the period ending December 31, 2011, will be allocated an amount of U.S. federal taxable income for that period that will be 50% or less of the cash distributed with respect to that period. We anticipate that after the taxable year ending December 31, 2011, the ratio of allocable taxable income to cash distributions to the unitholders will increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution of on all units and other assumptions with respect to capital expenditures, cash flow and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct. The actual ratio of taxable income could be higher or lower than our estimate, and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a unitholder who receives our common units in the distribution will be greater than 50% with respect to the period described above if:

- gross income from operations exceeds the amount required to make the minimum quarterly distribution on all units, yet we only distribute the minimum quarterly distribution on all its units; or

- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this distribution or to acquire property that is not eligible for depreciation or amortization for U.S. federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this distribution.

Basis of Our Common Units

A unitholder's initial adjusted basis for our common units received in the distribution by Atlas Energy generally will be determined as described under the heading "Certain U.S. Federal Income Tax Matters—Tax Consequences of the Distribution of Our Common Units by Atlas Energy—Basis and Holding Period" beginning on page 223. That basis will be (i) increased by such unitholder's share of our income and by any increases in such unitholder's share of our nonrecourse liabilities, and (ii) decreased, but not below zero, by distributions from us, by such unitholder's share of our losses, by any decreases in such unitholder's share of our nonrecourse liabilities and by such unitholder's share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner, but will have a share, generally based on such unitholder's share of profits, of our nonrecourse liabilities. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units—Recognition of Gain or Loss" beginning on page 234.

Limitations on Deductibility of Losses

The deduction by a unitholder of such unitholder's share of our losses will be limited to such unitholder's adjusted basis in our common units and, in the case of an individual unitholder or a corporate unitholder, if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by five or fewer individuals or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than such unitholder's adjusted basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause such unitholder's "at risk" amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that such unitholder's adjusted basis or "at risk" amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a common unit by such unitholder, any gain recognized by the unitholder can be offset by losses that were previously suspended by the "at risk" limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the "at risk" or basis limitations is no longer utilizable.

In general, a unitholder will be "at risk" to the extent of the unitholder's adjusted basis in our common units, excluding any portion of that basis attributable to the unitholder's share of our nonrecourse liabilities, reduced by any amount of money the unitholder borrows to acquire or hold the unitholder's common units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the common units for repayment. A unitholder's "at risk" amount will increase or decrease as the unitholder's adjusted basis of our common units increases or decreases, other than basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

In addition to the basis and the "at risk" limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally corporate or partnership activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. As a general rule, the passive loss limitations are applied separately with respect to each publicly traded partnership. However, the application of the passive loss limitations to tiered publicly traded partnerships is uncertain. We will take the position that any passive losses we generate that are reasonably allocable to our investment in other partnerships will only be available to offset our passive income generated in the future that is reasonably allocable to our investment in those other partnerships and will not be available to offset income from other passive activities or investments, including other investments in private businesses or investments we may make in other publicly traded partnerships. Moreover, because the passive loss limitations are applied separately with respect to each publicly traded partnership, any passive losses we generate will not be available to offset a unitholder's income from other passive activities or investments, including the unitholder's investments in other publicly traded partnerships or salary or active business income. Further, a unitholder's share of our net income may be offset by any suspended passive losses from the unitholder's investment in us, but may not be offset by our current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships. Passive losses that are not deductible because they exceed a unitholder's share of income generate may be deducted in full when the unitholder's disposes of the unitholder's entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss limitations are applied after other applicable limitations on deductions, including the "at risk" rules and the basis limitation.

Limitations on Interest Deductions

The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any U.S. federal, state, or local or foreign income tax on behalf of any unitholder or the general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend the partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under the partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual partner in which event the partner would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated to the unitholders in accordance with their percentage interests in us. If we have a net loss for the entire year, that loss will be allocated to the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to the general partner.

Specified items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of our assets at the time of any future offerings of our common stock or certain other transactions, referred to in this discussion as "Contributed Property." The effect of these allocations, referred to as "Section 704(c) Allocations," to a unitholder acquiring our common units in such future offerings or other transactions will be essentially the same as if the tax basis of our assets were equal to their fair market value at such time. However, in connection with providing this benefit to any future unitholders, similar allocations, will be made to all holders of partnership interests immediately prior to such other transactions, including U.S. holders who receive our common stock in this distribution, to account for the difference between the "book" basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of such issuance or future transaction.

In the event we issue additional units or engage in certain other transactions, "Reverse Section 704(c) Allocations," similar to the Section 704(c) Allocations described above, will be made to all holders of units immediately prior to such issuance or other transactions to account for the difference between the "book" basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of such issuance or other transactions.

In addition, items of recapture income will be allocated to the extent possible to the partner who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Furthermore, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in such amount and manner as is needed to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Code to eliminate the difference between a unitholder's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity," will generally be given effect for U.S. federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a unitholder's share of an item will be determined on the basis of the unitholder's interest in us, which will be determined by taking into account all the facts and circumstances, including:

- the unitholder's relative contributions to us;
- the interests of all the unitholders in profits and losses;
- the interest of all the unitholders in cash flow and other non-liquidating distributions; and
- the rights of all the unitholders to distributions of capital upon liquidation.

Treatment of Short Sales

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

- any of our income, gain, loss or deduction with respect to those common units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

The U.S. federal income tax treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units is uncertain. Therefore, 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. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. Please also read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units—Recognition of Gain or Loss" beginning on page 234.

Section 754 Election

We will make the election permitted by Section 754 of the Code. That election is irrevocable without the consent of the IRS. The election will generally permit us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Code to reflect such unitholder's purchase price. This election does not apply to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, a unitholder's inside basis in our assets will be considered to have two components: (1) the unitholder's share of our tax basis in our assets ("common basis") and (2) the unitholder's Section 743(b) adjustment to that basis.

U.S. Treasury regulations under Section 743 of the Code require, if the remedial allocation method is adopted (which we will adopt), a portion of the Section 743(b) adjustment attributable to recovery property to be depreciated over the remaining cost recovery period for the Section 704(c) built-in gain. Under U.S. Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Code, rather than cost recovery deductions under Section 168 of the Code, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, the general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these U.S. Treasury regulations. Please read "Certain U.S. Federal Income Tax Matters—Uniformity of Common Units."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of the property, or treat that portion as non-amortizable to the extent attributable to property the common basis of which is not amortizable. This method is consistent with the regulations under Section 743 of the Code but is arguably inconsistent with U.S. Treasury regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the U.S. Treasury regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read "Certain U.S. Federal Income Tax Matters—Uniformity of Common Units" beginning on page 236.

A Section 754 election is advantageous if the transferee's tax basis in the transferee's common units is higher than the common units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and the transferee's share of any gain or loss on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in the transferee's common units is lower than those common units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built in loss immediately after the transfer or if we distribute property and have a substantial basis reduction. Generally, a built in loss or a basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than the purchaser would have been allocated had the election not been revoked.

Tax Consequences of Our Operations

Accounting Method and Taxable Year

Our initial taxable year will end on December 31, 2011. Our taxable year may change after December 31, 2011, depending upon a number of factors. Each unitholder will be required to include in income such unitholder's share of our income, gain, loss and deduction for our taxable year ending within or with such unitholder's taxable year. For example, a unitholder who uses the calendar year will be required to include in such unitholder's income for 2011 such unitholder's share of our income, gain, loss and deduction for our taxable year ending December 31, 2011. In addition, a unitholder who has a different taxable year than our taxable year and who disposes of all of such unitholder's units following the close of our taxable year but before the close of such unitholder's taxable year must include his share of our income, gain, loss and deduction in income for such unitholder's taxable year, with the result that such unitholder will be required to include in income for such unitholder's taxable year such unitholder's share of more than one year of our income, gain, loss and deduction. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units—Allocations Between Transferors and Transferees" beginning on page 235.

Depletion Deductions

Subject to the limitations on deductibility of losses discussed above (please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Limitations on Deductibility of Losses" beginning on page 236), unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and natural gas interests. Although the Code requires each unitholder to compute the unitholder's own depletion allowance and maintain records of the unitholder's share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our unitholders with information relating to this computation for U.S. federal income tax purposes. Each unitholder, however, remains responsible for calculating its own depletion allowance and maintaining records of the unitholder's share of the adjusted tax basis of the underlying property for depletion and other purposes. Percentage depletion is generally available with respect to unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative contracts or the operation of a major refinery.

Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the unitholder's gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the unitholder from the property for each taxable year, computed without the depletion allowance. A unitholder who qualifies as an independent producer may deduct percentage depletion only to the extent the unitholder's average net daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000-barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a unitholder's total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the unitholder's total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

Unitholders who do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the unitholder's share of the adjusted tax basis in the underlying mineral property by the number of mineral units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the unitholder's share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the unitholder of some or all of the unitholder's units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the tax basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and U.S. Treasury regulations relating to the availability and calculation of depletion deductions by the unitholders. Further, because depletion is required to be computed separately by each unitholder and not by us, no assurance can be given with respect to the availability or extent of percentage depletion deductions to the unitholders for any taxable year. Moreover, the availability of percentage depletion may be reduced or eliminated if recently proposed (or similar) tax legislation is enacted. We encourage each unitholder to consult the unitholder's own tax advisor to determine whether percentage depletion would be available to the unitholder.

Deductions for Intangible Drilling and Development Costs

We will elect to currently deduct intangible drilling and development costs, or "IDCs." IDCs generally include our expenses for wages, fuel, repairs, hauling, supplies and other items that are incidental to, and necessary for, the drilling and preparation of wells for the production of oil, natural gas, or geothermal energy. The option to currently deduct IDCs applies only to those items that do not have a salvage value.

Although we will elect to currently deduct IDCs, each unitholder will have the option of either currently deducting IDCs or capitalizing all or part of the IDCs and amortizing them on a straight-line basis over a 60-month period, beginning with the taxable month in which the expenditure is made. If a unitholder makes the election to amortize the IDCs over a 60-month period, no IDC preference amount in respect of those IDCs will result for alternative minimum tax purposes.

Integrated oil companies must capitalize 30% of all their IDCs (other than IDCs paid or incurred with respect to oil and natural gas wells located outside of the United States) and amortize these IDCs over 60 months beginning in the month in which those costs are paid or incurred. If the taxpayer ceases to be an integrated oil company, it must continue to amortize those costs as long as it continues to own the property towhich the IDCs relate. An "integrated oil company" is a taxpayer that has economic interests in oil or natural gas properties and also carries on substantial retailing or refining operations. An oil or natural gas producer is deemed to be a substantial retailer or refiner if it is subject to the rules disqualifying retailers and refiners from taking percentage depletion. To qualify as an "independent producer" that is not subject to these IDC deduction limits, a unitholder, either directly or indirectly through certain related parties, may not be involved in the refining of more than 75,000 barrels of oil (or the equivalent amount of natural gas) on average for any day during the taxable year or in the retail marketing of oil and natural gas products exceeding $5 million per year in the aggregate.

IDCs previously deducted that are allocable to property (directly or through ownership of an interest in a partnership) and that would have been included in the adjusted tax basis of the property had the IDC deduction not been taken are recaptured to the extent of any gain realized upon the disposition of the property or upon the disposition by a unitholder of interests in us. Recapture is generally determined at the unitholder level. Where only a portion of the recapture property is sold, any IDCs related to the entire property are recaptured to the extent of the gain realized on the portion of the property sold. In the case of a disposition of an undivided interest in a property, a proportionate amount of the IDCs with respect to the property is treated as allocable to the transferred undivided interest to the extent of any gain recognized. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units—Recognition of Gain or Loss" beginning on page 234. The election to currently deduct IDCs may be restricted or eliminated if recently proposed (or similar) tax legislation is enacted. Each prospective unitholder is encouraged to consult his tax advisor regarding any deduction or amortization of IDCs, as well as any recapture.

Deduction for U.S. Production Activities

Subject to the limitations on the deductibility of losses discussed above (please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Limitations on Deductibility of Losses" beginning on page 192) and the limitation discussed below, unitholders will be entitled to a deduction, herein referred to as the "Section 199 deduction," equal to 6% of our qualified production activities income that is allocated to such unitholder, but not to exceed 50% of such unitholder's IRS Form W-2 wages for the taxable year allocable to domestic production gross receipts.

Qualified production activities income is generally equal to gross receipts from domestic production activities reduced by cost of goods sold allocable to those receipts, other expenses directly associated with those receipts, and a share of other deductions, expenses and losses that are not directly allocable to those receipts or another class of income. The products produced must be manufactured, produced, grown or extracted in whole or in significant part by the taxpayer in the United States.

For a partnership, the Section 199 deduction is determined at the partner level. To determine the unitholder's Section 199 deduction, each unitholder will aggregate the unitholder's share of the qualified production activities income allocated to the unitholder from us with the unitholder's qualified production activities income from other sources. Each unitholder must take into account the unitholder's distributive share of the expenses allocated to the unitholder from our qualified production activities regardless of whether we otherwise have taxable income. However, our expenses that otherwise would be taken into account for purposes of computing the Section 199 deduction are taken into account only if and to the extent the unitholder's share of losses and deductions from all of our activities is not disallowed by the tax basis rules, the at-risk rules or the passive activity loss rules. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Limitations on Deductibility of Losses" beginning on page 226.

The amount of a unitholder's Section 199 deduction for each year is limited to 50% of the IRS Form W-2 wages actually or deemed paid by the unitholder during the calendar year that are deducted in arriving at qualified production activities income. Each unitholder is treated as having been allocated IRS Form W-2 wages from us equal to the unitholder's allocable share of our wages that are deducted in arriving at qualified production activities income for that taxable year. It is not anticipated that we or our subsidiaries will pay material wages that will be allocated to our unitholders, and thus a unitholder's ability to claim the Section 199 deduction may be limited.

This discussion of the Section 199 deduction does not purport to be a complete analysis of the complex legislation and Treasury authority relating to the calculation of domestic production gross receipts, qualified production activities income, or IRS Form W-2 wages, or how such items are allocated by us to unitholders. Further, because the Section 199 deduction is required to be computed separately by each unitholder, no assurance can be given as to the availability or extent of the Section 199 deduction to the unitholders. Moreover, the availability of Section 199 deductions may be reduced or eliminated if recently proposed (or similar) tax legislation is enacted. Each prospective unitholder is encouraged to consult his tax advisor to determine whether the Section 199 deduction would be available to the unitholder.

Lease Acquisition Costs

The cost of acquiring oil and natural gas lease or similar property interests is a capital expenditure that must be recovered through depletion deductions if the lease is productive. If a lease is proved worthless and abandoned, the cost of acquisition less any depletion claimed may be deducted as an ordinary loss in the year the lease becomes worthless. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Our Operations—Depletion Deductions" beginning on page 230.

Geophysical Costs

The cost of geophysical exploration incurred in connection with the exploration and development of oil and natural gas properties in the United States are deducted ratably over a 24-month period beginning on the date that such expense is paid or incurred.

Operating and Administrative Costs

Amounts paid for operating a producing well are deductible as ordinary business expenses, as are administrative costs to the extent they constitute ordinary and necessary business expenses that are reasonable in amount.

Initial Tax Basis, Depreciation and Amortization

The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The tax basis of our assets we own at the time of this distribution will be greater to the extent such assets have been recently acquired. The U.S. federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to the distribution will be borne by our existing unitholders and unitholders who receive our common units in the distribution. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Allocation of Income, Gain, Loss and Deduction" beginning on page 227.

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own or will likely be required to recapture some or all of those deductions as ordinary income upon a sale of such unitholder's interest in us. Please read "Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Allocation of Income, Gain, Loss and Deduction" beginning on page 227 and "Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units—Recognition of Gain or Loss" beginning on page 234.

Valuation and Tax Basis of Our Properties

The U.S. federal income tax consequences of the ownership and disposition of common units will depend in part on our estimates of the relative fair market values, and the initial tax bases of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Tax Consequences of Disposition of Our Common Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of our common units equal to the difference between the amount realized and the unitholder's tax basis for the common units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by such unitholder plus such unitholder's share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder on the sale or exchange of a common unit held for more than one year will generally be taxable as capital gain or loss. However, a portion of this gain or loss will be separately computed and taxed as ordinary income or loss under Section 751 of the Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of common units. Net capital losses may offset capital gains and no more than $3,000 of ordinary income in the case of individuals.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in such partner's entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. U.S. Treasury regulations under Section 1223 of the Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling discussed above, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the U.S. Treasury regulations, may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult such unitholder's tax advisor as to the possible consequences of this ruling and application of the U.S. Treasury regulations.

Specific provisions of the Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this summary as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Code and most publicly-traded partnerships use similar simplifying conventions, the use of this method may not be permitted under existing U.S. Treasury regulations. Recently, however, the Department of the Treasury and the IRS issued proposed U.S. Treasury Regulations that provide a safe harbor pursuant to which a publicly-traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, although such tax items must be prorated on a daily basis. Nonetheless, the proposed U.S. Treasury regulations do not specifically authorize the use of the proration method we have adopted. Existing publicly-traded partnerships are entitled to rely on those proposed U.S. Treasury regulations; however, they are not binding on the IRS and are subject to change until the final U.S. Treasury regulations are issued. If our method of allocating income and deductions between transferee and transferor unitholders is not allowed under the U.S. Treasury regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferee and transferor unitholders, as well as among unitholders whose interests vary during a taxable year, to conform to a method permitted under future U.S. Treasury regulations.

A unitholder who disposes of common units prior to the record date set for a cash distribution for any quarter will be allocated items of our income, gain, loss and deductions attributable to the month of sale but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his units other than through a broker generally is required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder is generally required to notify us in writing of that purchase within 30 days after the purchase, unless a broker or nominee will satisfy such requirement. We are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker.

Constructive Termination

We will be considered to have been terminated for U.S. federal income 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. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Common Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of U.S. federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of U.S. Treasury regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read “Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Section 754 Election” beginning on page 229.

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of that property, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Code, even though that position may be inconsistent with U.S. Treasury regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read “Certain U.S. Federal Income Tax Matters—Tax Consequences of Ownership of Our Common Units—Section 754 Election” beginning on page 229. To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the U.S. Treasury regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read “Certain U.S. Federal Income Tax Matters—Tax Consequences of Disposition of Our Common Units—Recognition of Gain or Loss” beginning on page 234.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each taxable year, specific tax information, including an IRS Schedule K-1, which describes the unitholder's share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure our unitholders that those positions will yield a result that conforms to the requirements of the Code, the U.S. Treasury regulations or administrative interpretations of the IRS. Nor can we assure unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the common units.

The IRS may audit our U.S. federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of the unitholder's own return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to his returns.

Partnerships generally are treated as separate entities for purposes of U.S. federal income tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. Our partnership agreement designates our general partner as our Tax Matters Partner.

The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate in that action.

A unitholder must file a statement with the IRS identifying the treatment of any item on the unitholder's U.S. federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- a statement regarding whether the beneficial owner is: (a) a person that is not a U.S. person; (b) a non-U.S. government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or (c) a tax-exempt entity;
- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $100 per failure, up to a maximum of $1,500,000 per calendar year, is imposed by the Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties

An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for the underpayment of that portion and that the taxpayer acted in good faith regarding the underpayment of that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000. The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, "substantial authority"; or
- as to which there is a reasonable basis and the relevant facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the relevant facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty. More stringent rules apply to "tax shelters," which we do not believe includes us, or any of our investments, plans or arrangements.

A substantial valuation misstatement exists if (a) the value of any property, or the adjusted tax basis of any property, claimed on a tax return is 150% or more of the amount determined to be the correct amount of the valuation or adjusted tax basis, (b) the price for any property or services (or for the use of property) claimed on any such return with respect to any transaction between persons described in Section 482 of the Code is 200% or more (or 50% or less) of the amount determined under Section 482 to be the correct amount of such price, or (c) the net transfer price adjustment under Section 482 for the taxable year exceeds the lesser of $5 million or 10% of the taxpayer's gross receipts. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for a corporation other than an S Corporation or a personal holding company). The penalty is increased to 40% in the event of a gross valuation misstatement. We do not anticipate making any valuation misstatements.

Reportable Transactions

If we were to engage in a "reportable transaction," we (and possibly our unitholders and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses for partnerships, individuals, S corporations, and trusts in excess of $2 million in any single tax year, or $4 million in any combination of six successive tax years. Our participation in a reportable transaction could increase the likelihood that our U.S. federal income tax information return (and possibly our unitholders' tax return) would be audited by the IRS. Please read "Certain U.S. Federal Income Tax Matters—Administrative Matters—Information Returns and Audit Procedures" beginning on page 237.

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, our unitholders may be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described in "Certain U.S. Federal Income Tax Matters—Administrative Matters—Accuracy-Related Penalties" on page 238;
- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability; and
- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any "reportable transactions."

WHERE YOU CAN FIND MORE INFORMATION

We have filed a registration statement on Form 10 with the SEC with respect to our common units that Atlas Energy unitholders will receive in the distribution. This information statement is a part of that registration statement and, as allowed by SEC rules, does not include all of the information you can find in the registration statement or the exhibits to the registration statement. For additional information relating to our company and the distribution, reference is made to the registration statement and the exhibits to the registration statement. Statements contained in this information statement as to the contents of any contract or document referred to are not necessarily complete and in each instance, if the contract or document is filed as an exhibit to the registration statement, we refer you to the copy of the contract or other document filed as an exhibit to the registration statement. Each such statement is qualified in all respects by reference to the applicable document.

After the distribution, we will file annual, quarterly and special reports, proxy statements and other information with the SEC. We intend to furnish our unitholders with annual reports containing consolidated financial statements audited by an independent registered public accounting firm. The registration statement is, and any of these future filings with the SEC will be, available to the public over the Internet on the SEC's website at *www.sec.gov*. You may read and copy any filed document at the SEC's public reference rooms at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information about the public reference rooms.

We intend to establish an Internet site at *www.atlasresourcepartners.com*. Our website and the information contained on that site, or connected to that site, are not incorporated into this information statement or the registration statement on Form 10.

GLOSSARY OF TERMS

As commonly used in the oil and gas industry and as used in this information statement, the following terms have the following meanings:

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.

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.

Developed acres. 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. 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.

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.

Extension well. A well drilled to extend the limits of a known reservoir.

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.

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.

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

MMcfed. One Mmcfe per day.

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

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

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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

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.

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.

Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation and injection for in-situ combustion.

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.

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.

INDEX TO FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

INDEX TO COMBINED FINANCIAL STATEMENTS AND SCHEDULE

ATLAS RESOURCE PARTNERS, L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

The following unaudited pro forma condensed combined financial statements of Atlas Resource Partners, L.P. reflect the historical combined financial statements of Atlas Energy E&P Operations (the "Predecessor") included elsewhere in this information statement, and were adjusted on a pro forma basis to give effect to the following transactions:

- the contribution by Atlas Energy, L.P. to us of the assets and liabilities that comprise our business;
- the issuance of 26,200,000 of our common units, of which approximately 20.96 million common units will be distributed to holders of Atlas Energy common units and the remaining approximately 5.24 million common units will be retained by Atlas Energy. This number of common units is based upon the number of Atlas Energy common units outstanding on February 28, 2012 and a distribution ratio of 0.1021 of a common unit of Atlas Resource Partners for each common unit of Atlas Energy; and
- the impact of a separation agreement between us and Atlas Energy and the provisions contained therein.

The unaudited pro forma condensed combined statements of operations for the nine months ended September 30, 2011 and 2010 and for the year ended December 31, 2010 reflect our results as if the separation and related transactions described above had occurred as of January 1, 2011, January 1, 2010 and January 1, 2010, respectively. The unaudited pro forma condensed combined balance sheet as of September 30, 2011 reflects our results as if the separation and related transactions described above had occurred as of such date.

The unaudited pro forma condensed combined financial statements have been prepared on the basis that we will be treated as a partnership for federal income tax purposes. The unaudited pro forma condensed combined financial statements should be read in conjunction with our "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 99 and our Predecessor's audited and unaudited interim combined financial statements and corresponding notes beginning on page F-12.

The unaudited pro forma condensed combined financial statements included in this information statement do not necessarily reflect what our financial position and results of operations would have been if we had operated as an independent, publicly traded company during the periods shown. In addition, they are not necessarily indicative of our future results of operations or financial condition. The assumptions and estimates used and pro forma adjustments derived from such assumptions are based on currently available information, and we believe such assumptions are reasonable under the circumstances.

The unaudited pro forma condensed combined financial statements do not include certain non-recurring separation costs that we expect to incur in connection with the separation. Excluded are one-time expenditures estimated at $2.0 million to $4.0 million related to one-time transaction-related costs. We expect to fund these costs through cash from operations, cash on hand and, if necessary, cash available from the senior secured revolving credit facility we anticipate entering into simultaneously with the closing of the transactions described above. Due to the scope and complexity of these activities, the amount of these costs could increase or decrease materially and the timing of incurrence could change.

The Predecessor's principal assets and liabilities (the "Transferred Business") were acquired on February 17, 2011 from Atlas Energy, Inc. ("Old Atlas"), the former owner of Atlas Energy's general partner. In accordance with prevailing accounting literature, the management of Atlas Energy determined that the acquisition of the Transferred Business constituted a transaction between entities under common control. Among other items, 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. 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 Atlas Energy's consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. The Transferred Business' historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by Old Atlas to the underlying business segments, including the aggregation of assets and liabilities now defined as the Predecessor. We have reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas 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.

ATLAS RESOURCE PARTNERS, L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED BALANCE SHEET
AS OF SEPTEMBER 30, 2011
(in thousands)

	Atlas Energy E&P Operations Historical	Pro Forma Adjustments	Atlas Resource Partners, L.P. Pro Forma
ASSETS			
Current assets:			
Cash and cash equivalents	$ 59,986	$ 2,000 (a)	$ 59,986
		(2,000) (a)	
Accounts receivable	25,858	—	25,858
Advances to affiliates	2,676	—	2,676
Current portion of derivative asset	6,111	—	6,111
Prepaid expenses and other	7,246	—	7,246
Total current assets	101,877	—	101,877
Property, plant and equipment, net	526,634	—	526,634
Intangible assets, net	1,652	2,000 (a)	3,652
Goodwill, net	31,784	—	31,784
Long-term derivative assets	7,349	—	7,349
	$669,296	$ 2,000	$671,296
LIABILITIES AND EQUITY/PARTNERS' CAPITAL			
Current liabilities:			
Current portion of long-term debt	$ —	$ 2,000 (a)	$ 2,000
Accounts payable	40,405	—	40,405
Liabilities associated with drilling contracts	33,194	—	33,194
Current portion of derivative payable to drilling partnerships	23,664	—	23,664
Accrued well drilling and completion costs	17,433	—	17,433
Accrued liabilities	20,576	—	20,576
Total current liabilities	135,272	2,000	137,272
Long-term derivative payable to drilling partnerships	19,808	—	19,808
Asset retirement obligations	44,840	—	44,840
Equity/Partners' Capital:			
Equity	455,916	(455,916) (b)	—
General partner's interest	—	9,118 (b)	9,118
Common limited partners' interests	—	446,798 (b)	446,798
Accumulated other comprehensive income	13,460	—	13,460
Total equity/partners' capital	469,376	—	469,376
	$669,296	$ 2,000	$671,296

See accompanying notes to unaudited pro forma combined financial statements.

ATLAS RESOURCE PARTNERS, L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENTS OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2011
(in thousands)

	Atlas Energy E&P Operations Historical	Pro Forma Adjustments		Atlas Resource Partners, L.P. Pro Forma	
Revenues:					
Gas and oil production	$ 51,654	$ —		$ 51,654	
Well construction and completion	64,336	—		64,336	
Gathering and processing	14,048	—		14,048	
Administration and oversight	5,073	—		5,073	
Well services	15,051	—		15,051	
Total revenues	150,162	—		150,162	
Costs and expenses:					
Gas and oil production	11,953	—		11,953	
Well construction and completion	54,754	—		54,754	
Gathering and processing	16,377	—		16,377	
Well services	6,077	—		6,077	
General and administrative	12,275	—		12,275	
Depreciation, depletion and amortization	24,019	—		24,019	
Total costs and expenses	125,455	—		125,455	
Operating income	24,707	—		24,707	
Interest expense	—	(38)	(c)	(338)	
		(300)	(d)		
Net income	$24,707	$(338)		$ 24,369	
Allocation of net income attributable to common limited partners and the general partner:					
General partners' interest	$ —			$ 487	(e)
Common limited partners' interest	—			23,882	(e)
Net income	$ —			$ 24,369	
Net income attributable to common limited partners per unit:					
Basic	$ —			$ 0.91	
Diluted	$ —			$ 0.91	
Weighted average common limited partner units outstanding:					
Basic	—			26,200	(f)
Diluted	—			26,200	(f)

See accompanying notes to unaudited pro forma condensed combined financial statements.

ATLAS RESOURCE PARTNERS, L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENTS OF OPERATIONS NINE MONTHS ENDED SEPTEMBER 30, 2010 (in thousands)

	Atlas Energy E&P Operations Historical	Pro Forma Adjustments		Atlas Resource Partners, L.P. Pro Forma	
Revenues:					
Gas and oil production	$ 70,816	$ —		$ 70,816	
Well construction and completion	176,685	—		176,685	
Gathering and processing	11,414	—		11,414	
Administration and oversight	7,473	—		7,473	
Well services	15,589	—		15,589	
Other, net	—	—		—	
Total revenues	281,977	—		281,977	
Costs and expenses:					
Gas and oil production	16,863	—		16,863	
Well construction and completion	149,724	—		149,724	
Gathering and processing	16,499	—		16,499	
Well services	7,691	—		7,691	
General and administrative	8,536	—		8,536	
Depreciation, depletion and amortization	31,929	—		31,929	
Total costs and expenses	231,242	—		231,242	
Operating income	50,735	—		50,735	
Loss on asset sales	(2,947)	—		(2,947)	
Interest expense	—	(38)	(c)	(338)	
		(300)	(d)		
Net income	$ 47,788	$(338)		$ 47,450	
Allocation of net income attributable to common limited partners and the general partner:					
General partners' interest	$ —			$ 949	(e)
Common limited partners' interest	—			46,501	(e)
Net income	$ —			$ 47,450	
Net income attributable to common limited partners per unit:					
Basic	$ —			$ 1.77	
Diluted	$ —			$ 1.77	
Weighted average common limited partner units outstanding:					
Basic	—			26,200	(f)
Diluted	—			26,200	(f)

See accompanying notes to unaudited pro forma condensed combined financial statements.

ATLAS RESOURCE PARTNERS, L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2010
(in thousands)

	Atlas Energy E&P Operations Historical	Pro Forma Adjustments		Atlas Resource Partners, L.P. Pro Forma	
Revenues:					
Gas and oil production	$ 93,050	$ —		$ 93,050	
Well construction and completion	206,802	—		206,802	
Gathering and processing	14,087	—		14,087	
Administration and oversight	9,716	—		9,716	
Well services	20,994	—		20,994	
Total revenues	344,649	—		344,649	
Costs and expenses:					
Gas and oil production	23,323	—		23,323	
Well construction and completion	175,247	—		175,247	
Gathering and processing	20,221	—		20,221	
Well services	10,822	—		10,822	
General and administrative	11,381	—		11,381	
Depreciation, depletion and amortization	40,758	—		40,758	
Asset impairment	50,669	—		50,669	
Total costs and expenses	332,421	—		332,421	
Operating income	12,228	—		12,228	
Loss on asset sales	(2,947)	—		(2,947)	
Interest expense	—	(50)	(c)	(450)	
		(400)	(d)		
Net income	$ 9,281	$(450)		$ 8,831	
Allocation of net income attributable to common limited partners and the general partner:					
General partners' interest	$ —			$ 177	(e)
Common limited partners' interest	—			8,654	(e)
Net income	$ —			$ 8,831	
Net income attributable to common limited partners per unit:					
Basic	$ —			$ 0.33	
Diluted	$ —			$ 0.33	
Weighted average common limited partner units outstanding:					
Basic	—			26,200	(f)
Diluted	—			26,200	(f)

See accompanying notes to unaudited pro forma condensed combined financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

a) To reflect the payment of $2 million of estimated fees and expenses associated with entering into the new senior secured revolving credit facility we anticipate entering into simultaneously with the closing of the separation and related transactions, which will be financed with borrowings under the new credit facility. The estimated fees and expenses will be recognized as deferred finance costs within intangible assets, net, on the unaudited pro forma condensed combined balance sheet and amortized over the anticipated term of the senior secured credit facility, which is assumed to be five years.

b) To reflect the contribution by Atlas Energy of substantially all of its assets and liabilities associated with its natural gas and oil development and production assets and its partnership management business to Atlas Resource Partners, L.P. The contribution of assets was recorded at historical cost because it is considered to be a reorganization of entities under common control. To reflect the impact of the contribution within equity/partners' capital on the unaudited pro forma condensed combined balance sheet, the historical equity of Atlas Energy E&P Operations was eliminated and reallocated to Atlas Resource Partners' partners' capital, with approximately 2% of the balance allocated to the general partner's interest and the remainder allocated to limited partners' interests, which reflects their respective ownership interests.

c) To reflect the adjustment to interest expense to finance the $2 million of borrowings under Atlas Resource Partners new senior secured revolving credit facility (as discussed in note (a)) at an interest rate of 2.5%, based upon current market conditions.

d) To reflect the amortization of the $2 million of deferred finance costs associated with the new senior secured credit facility, which is amortized over the five-year assumed term of the facility (as discussed in note (a)).

e) To reflect the allocation of net income to the general partner and limited partners' interests of Atlas Resource Partners. The general partner's ownership interest in net income is calculated on a quarterly basis based upon its 2% general partner interest and incentive distributions, in accordance with the partnership agreement, with the remaining net income or loss allocated to the limited partners' ownership interests.

f) To reflect Atlas Resource Partners outstanding common limited partner interests upon the completion of the separation and related transactions.

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. (the "Partnership") as of October 13, 2011. This financial statement is the responsibility of the Partnership's management. Our responsibility is to express an opinion on this balance sheet 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 statements are free of material misstatement. The Partnership 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 Partnership'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 audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of Atlas Resource Partners, L.P. at October 13, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ Grant Thornton LLP

Tulsa, Oklahoma
October 14, 2011

ATLAS RESOURCE PARTNERS, L.P.

BALANCE SHEET

	October 13, 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.

NOTE TO BALANCE SHEET
October 13, 2011

NOTE 1—Nature of Operations

Atlas Resource Partners, L.P. (the "Partnership") is a Delaware limited partnership formed in October 2011.

Atlas Energy, L.P. intends to contribute to the Partnership substantially all of its assets and liabilities associated with its natural gas and oil assets and the partnership management business. Simultaneously, Atlas Energy intends to distribute approximately 20% of the outstanding common units of the Partnership to its unitholders.

Atlas Energy has committed to contribute $1,000 as the organizational partner on October 13, 2011. There have been no other transactions involving the Partnership as of October 13, 2011.

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, 2010 and 2009, and the related combined statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the combined financial statements have been restated for the inclusion of an allocation of general and administrative expenses in each of the years presented.

/s/ Grant Thornton LLP

Tulsa, Oklahoma
October 14, 2011, (except for Note 2 as to which the date is December 29, 2011)

ATLAS ENERGY E&P OPERATIONS

COMBINED BALANCE SHEETS
(in thousands)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Accounts receivable	$ 20,800	$ 29,476
Current portion of derivative asset	36,621	34,123
Subscription receivable from drilling partnerships	—	46,884
Prepaid expenses and other	8,585	10,568
Total current assets	66,006	121,051
Property, plant and equipment, net	508,484	503,386
Intangible assets, net	2,164	2,874
Goodwill, net	31,784	31,784
Long-term derivative asset	36,125	28,667
Long-term derivative receivable from drilling partnerships	4,669	2,841
	$649,232	$690,603
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 45,957	$ 49,107
Liabilities associated with drilling contracts	65,072	122,532
Current portion of derivative liability	353	412
Current portion of derivative payable to drilling partnerships	30,797	22,382
Accrued well drilling and completion costs	30,126	68,138
Accrued liabilities	11,283	12,876
Total current liabilities	183,588	275,447
Long-term derivative liability	6,293	4,591
Long-term derivative payable to drilling partnerships	34,796	22,380
Asset retirement obligation	42,673	36,599
Commitments and contingencies		
Equity:		
Equity	376,567	335,449
Accumulated other comprehensive income	5,315	16,137
Total equity	381,882	351,586
	$649,232	$690,603

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF OPERATIONS
(in thousands)

	Years Ended December 31,		
	2010	2009	2008
Revenues:	(Restated)	(Restated)	(Restated)
Gas and oil production	$ 93,050	$112,979	$127,083
Well construction and completion	206,802	372,045	415,036
Gathering and processing	14,087	18,839	19,098
Administration and oversight	9,716	15,554	19,277
Well services	20,994	17,859	18,513
Total revenues	344,649	537,276	599,007
Costs and expenses:			
Gas and oil production	23,323	25,557	25,104
Well construction and completion	175,247	315,546	359,609
Gathering and processing	20,221	25,269	19,098
Well services	10,822	9,330	10,654
General and administrative	11,381	15,832	13,074
Depreciation, depletion and amortization	40,758	43,712	39,781
Asset impairment	50,669	156,359	—
Total costs and expenses	332,421	591,605	467,320
Operating income (loss)	12,228	(54,329)	131,687
Loss on asset sales	(2,947)	—	—
Net income (loss)	$ 9,281	$ (54,329)	$131,687

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Years Ended December 31,		
	2010 (Restated)	2009 (Restated)	2008 (Restated)
Net income (loss)	$ 9,281	$(54,329)	$131,687
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as cash flow hedges	16,542	27,846	23,956
Less: reclassification adjustment for realized losses (gains) in net income (loss)	(27,364)	(43,745)	4,934
Total other comprehensive income (loss)	(10,822)	(15,899)	28,890
Comprehensive income (loss) attributable to owner	$ (1,541)	$(70,228)	$160,577

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF EQUITY
(in thousands)

	Equity	Accumulated Other Comprehensive Income (Loss)	Total
	(Restated)		(Restated)
Balance at January 1, 2008	$245,269	$ 3,146	$248,415
Net investment from Atlas Energy, Inc.	106,630	—	106,630
Other comprehensive income	—	28,890	28,890
Net income	131,687	—	131,687
Balance at December 31, 2008	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

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2010	2009	2008
	(Restated)	(Restated)	(Restated)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 9,281	$ (54,329)	$ 131,687
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	40,758	43,712	39,781
Long-lived asset impairment	50,669	156,359	—
Loss on asset sales	2,947	—	—
Non-cash (gain) loss on derivative value, net	—	(3,022)	3,022
Changes in operating assets and liabilities:			
Accounts receivable and prepaid expenses and other	53,751	103	(56,653)
Accounts payable and accrued liabilities	(96,820)	49,378	51,441
Net cash provided by operating activities	60,586	192,201	169,278
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(93,608)	(99,302)	(264,125)
Other	1,185	909	1,972
Net cash used in investing activities	(92,423)	(98,393)	(262,153)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net investment received from Atlas Energy, Inc. (see Note 3)	31,837	—	92,875
Net distribution to Atlas Energy, Inc. (see Note 3)	—	(93,808)	—
Net cash provided by (used in) financing activities	31,837	(93,808)	92,875
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents, beginning of period	—	—	—
Cash and cash equivalents, end of period	$ —	$ —	$ —

See accompanying notes to combined financial statements.

NOTE 1—BASIS OF PRESENTATION

On February 17, 2011, Atlas Energy, L.P. (the "Partnership"; NYSE: ATLS), a publicly-traded Delaware limited partnership formerly known as Atlas Pipeline Holdings, L.P., acquired certain producing natural gas and oil properties, a partnership management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, and other assets (the "Transferred Business") from Atlas Energy, Inc. ("Old Atlas"), the former owner of its general partner. Atlas Energy E&P Operations (the "Company") consists of assets, liabilities, equity and operations of the subsidiaries of the Partnership which hold the natural gas and oil properties and direct investment business. The Partnership intends to transfer substantially all of the assets, liabilities and operations of the Company to Atlas Resource Partners, L.P. ("Atlas Resource Partners") and issue approximately 20% of Atlas Resource Partners' outstanding common limited partner interests to the Partnership's limited partners.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Combination

The combined balance sheets at December 31, 2010 and 2009 and the related combined statements of operations for the years ended December 31, 2010, 2009 and 2008 were derived from the separate records maintained by the Partnership 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, the Partnership'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 the Partnership, 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 Partnership operations have been identified in the combined statements as transactions between affiliates (see Note 3).

In accordance with prevailing accounting literature, management of the Partnership 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 the Partnership's partners' capital on its consolidated 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 Partnership's consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, the Partnership reflected the impact of the acquisition of the Transferred Business on its consolidated combined financial statements, from which the Company's combined financial statements were derived, 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 historical consolidated 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 historical consolidated combined statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners. The Transferred Business' historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by Old Atlas to the underlying business segments, including the aggregation of assets and liabilities now defined as the Predecessor. The Company has reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas 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 15% to 35%. 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.

Restatement – General and Administrative Expenses

The Company has restated its financial statements to reflect an allocation of general and administrative expenses related to the Transferred Business for the years ended December 31, 2010, 2009 and 2008 in order to comply with the Securities and Exchange Commission's Staff Accounting Bulletin Topic 1, Paragraph B1 *"Allocation of Expenses and Related Disclosure in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity"*. The Company has reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas and the Transferred Business, for the Transferred Business' historical financial statements prior to the date of acquisition and believes the methodology is reasonable and reflects the approximate general and administrative costs of its underlying business segments.

The adjustment to net income for the three years ended December 31, 2010, 2009 and 2008 is summarized below (in thousands):

	Years Ended December 31,		
	2010	**2009**	**2008**
Net income (loss), as previously reported	$ 20,662	$(38,497)	$144,761
General and administrative expenses	(11,381)	(15,832)	(13,074)
Net income (loss), as restated	$ 9,281	$(54,329)	$131,687

The impact of the restatement on the consolidated statements of cash flows is summarized below (in thousands):

	December 31, 2010	
	As Previously Reported	As Restated
Net income	$ 20,662	$ 9,281
Net cash provided by operating activities	71,967	60,586
Net investment received from Atlas Energy, Inc	20,456	31,837
Net cash provided by financing activities	20,456	31,837

	December 31, 2009	
	As Previously Reported	As Restated
Net loss	$ (38,497)	$ (54,329)
Net cash provided by operating activities	208,033	192,201
Net distribution to Atlas Energy, Inc	(109,640)	(93,808)
Net cash used in financing activities	(109,640)	(93,808)

	December 31, 2008	
	As Previously Reported	As Restated
Net income	$ 144,761	$131,687
Net cash provided by operating activities	182,352	169,278
Net investment received from Atlas Energy, Inc	79,801	92,875
Net cash provided by financing activities	79,801	92,875

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 the Partnership in order to derive the historical period financial statements of the Company. Actual results could differ from those estimates.

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 the Company's accounts receivable, management performs ongoing credit evaluations of the Company's customers and adjusted credit limits based upon payment history and the customer's current creditworthiness, as determined by the Partnership's management's review of the customers' credit information. The Partnership extends credit on sales on an unsecured basis to many of the Company's customers. At December 31, 2010 and 2009, there was no allowance for uncollectible accounts receivable related to the Upstream Oil and Gas Business on its combined balance sheets.

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" beginning on page F-18). 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 combined 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 its 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, 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 7% 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 partnership'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 partnerships' 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 partnerships' 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 oil and gas properties recorded by the Company for the years ended December 31, 2010, 2009 and 2008.

During the year ended December 31, 2010, the Company recognized a $50.7 million asset impairment related to oil and gas properties within property, plant and equipment on its combined balance sheet for its shallow natural gas wells in Tennessee and Ohio. During the year ended December 31, 2009, the Company recorded a $156.4 million asset impairment related to oil and gas properties within property, plant and equipment on its combined balance sheet for shallow natural gas wells in the Upper Devonian shale. These impairments related to the carrying amount of these oil and gas properties being in excess of the Company's estimate of their fair value at December 31, 2010 and 2009, respectively. The estimate of the fair value of these oil and gas properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement. There were no impairments of proved oil and gas properties recorded by the Company for the year ended December 31, 2008.

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, 2010 and 2009 (in thousands):

	December 31,		Estimated Useful Lives In Years
	2010	2009	
Gross Carrying Amount	$ 14,344	$ 14,344	1 – 13
Accumulated Amortization	(12,180)	(11,470)	
Net Carrying Amount	$ 2,164	$ 2,874	

Amortization expense on intangible assets was $0.7 million, $1.0 million and $1.2 million for the years ended December 31, 2010, 2009 and 2008, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2011 – $0.7 million; 2012 – $0.2 million; 2013 – $0.2 million; 2014 – $0.1 million; and 2015 – $0.1 million.

Goodwill

At December 31, 2010 and 2009, the Company had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions.

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, management must apply judgment in determining the estimated fair value of these reporting units. 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. The fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in its industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate the goodwill at least annually or when impairment indicators arise.

Derivative Instruments

The Company had certain financial contracts to manage its exposure to movement in commodity (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 were 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 recognized an estimated liability for the plugging and abandonment of its oil and gas 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. Asset retirement obligations and the related assets were determined based on the historical cost of the natural gas and oil properties included within the Company.

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, 2010 and 2009, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

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 180 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 natural gas liquids 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 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). Generally, the Company's sales contracts are based on pricing provisions that are tied to a market index, which is generally fixed 2 business days prior to the commencement of the production month, with certain fixed adjustments based on proximity to gathering and transmission lines and the quality of its natural gas. The Company had unbilled revenues at December 31, 2010 and 2009 of $20.8 million and $29.7 million, respectively, which were included in accounts receivable within its combined balance sheets.

Comprehensive Income

Comprehensive income includes net income 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. These changes, other than net income, are referred to as "other comprehensive income" 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 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. 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 June 2011, the FASB issued Accounting Standards Update 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income ("Update 2011-05"). Update 2011-05 amends the FASB Accounting Standards Codification to provide an entity with 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. These changes apply to both annual and interim financial statements. Update 2011-05 will be effective for public entities' fiscal years, and interim periods within those years, beginning after December 15, 2011. The Company will apply the requirements of Update 2011-05 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—ACQUISITION FROM ATLAS ENERGY, INC.

On February 17, 2011, the Partnership acquired the Transferred Business, including the assets and liabilities of the Company, from Old Atlas, the former parent of its general partner, which included the following assets:

- Old Atlas' investment management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which the Company will fund 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 will be a developer and producer;
- all of the ownership interests in Atlas Energy GP, LLC, the Partnership'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, the Partnership issued approximately 23.4 million of its common limited partner units and paid $30.0 million in cash consideration. Based on the Partnership's February 17, 2011 common unit closing price of $15.92, the common units issued to Old Atlas were valued at approximately $372.2 million. In connection with the transaction, the Partnership also received $124.7 million with respect to a contractual cash transaction adjustment from old Atlas related to certain liabilities assumed by the Partnership. Including the cash transaction adjustment, the net book value of the assets acquired was approximately $528.7 million.

Concurrent with the Partnership's acquisition of assets, including the assets and liabilities of the Company, Old Atlas completed its merger with Chevron Corporation ("Chevron"), whereby Old Atlas became a wholly owned subsidiary of Chevron.

Also concurrent with the Partnership's acquisition of assets and immediately preceding Old Atlas' merger with Chevron, Atlas Pipeline Partners, L.P. ("APL"), a publicly-traded limited partnership (NYSE: APL) in which the Partnership owns a 2% general partner interest, all of the incentive distribution rights, and an approximate 10.7% common limited partner interest at September 30, 2011, completed its sale to Old Atlas 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.

In accordance with prevailing accounting literature, management of the Partnership determined that the acquisition of the Transferred Business constituted a transaction between entities under common control (see Note 3). As such, the Partnership recognized the assets acquired and liabilities assumed at historical carrying value at the date of acquisition, with the difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital on its consolidated combined balance sheet. The Partnership recognized a non-cash decrease of $254.5 million in partners' capital on its consolidated combined balance sheet based on the excess net book value above the value of the consideration paid to Old Atlas. The following table presents the historical carrying value of the assets acquired and liabilities assumed by the Partnership, including the effect of cash transaction adjustments, as of February 17, 2011 (in thousands):

Cash	$159,180
Accounts receivable	18,090
Accounts receivable—affiliate	45,682
Prepaid expenses and other	6,955
Total current assets	229,907
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	$800,839
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	$528,704

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

NOTE 4—PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2010	December 31, 2009	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$ 46,495	$ 42,199	
Pre-development costs	2,337	2,472	
Wells and related equipment	798,269	724,673	
Total proved properties	847,101	769,344	
Unproved properties	42,520	40,189	
Support equipment	8,138	5,792	
Total natural gas and oil properties	897,759	815,325	
Pipelines, processing and compression facilities	30,072	22,203	2 – 40
Rights of way	84	6	20 – 40
Land, buildings and improvements	5,632	3,590	3 – 40
Other	4,727	3,542	3 – 10
	938,274	844,666	
Less—accumulated depreciation, depletion and amortization	(429,790)	(341,280)	
	$ 508,484	$ 503,386	

During the year ended December 31, 2010, the Company recognized a $50.7 million asset impairment related to oil and gas properties within property, plant and equipment on its combined balance sheet for its shallow natural gas wells in Tennessee and Ohio. During the year ended December 31, 2009, the Company recorded a $156.4 million asset impairment related to oil and gas properties within property, plant and equipment on its combined balance sheet for shallow natural gas wells in the Upper Devonian shale. These impairments related to the carrying amount of these oil and gas properties being in excess of the Company's estimate of their fair value at December 31, 2010 and 2009, respectively. The estimate of fair value of these oil and gas properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement. There were no impairments of proved oil and gas properties recorded by the Company for the year ended December 31, 2008.

NOTE 5—ASSET RETIREMENT OBLIGATIONS

The Company recognizes an estimated liability for the plugging and abandonment of its oil and gas 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 oil and gas 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,		
	2010	2009	2008
Asset retirement obligations, beginning of year	$36,599	$33,881	$30,264
Liabilities incurred	472	909	1,972
Liabilities settled	(373)	(248)	(230)
Accretion expense	2,205	2,057	1,875
Revisions	3,770	—	—
Asset retirement obligations, end of year	$42,673	$36,599	$33,881

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 its commodity 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 is sold. Under 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 Company's 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 for 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 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 a net derivative asset of $66.1 million and $57.8 million at December 31, 2010 and 2009, respectively. Of the $5.3 million of net gain in accumulated other comprehensive income within equity on the Company's combined balance sheet related to derivatives at December 30, 2010, if the fair values of the instruments remain at current market values, the Company will reclassify $5.6 million of gains to gas and oil production revenues to its combined statements of operations over the next twelve-month period as these contracts expire. Aggregate losses of gas and oil production revenues of $0.3 million will be reclassified to the Company's combined statements of operations in later periods as these 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 derivative instruments as of December 31, 2010 and 2009, as well as the gain or loss recognized in the combined statements of operations for effective derivative instruments for the years ended December 31, 2010, 2009 and 2008:

Contract Type	Balance Sheet Location	December 31, 2010	December 31, 2009
Commodity contracts	Current portion of derivative asset	$36,621	$34,123
Commodity contracts	Long-term derivative asset	36,125	28,667
		72,746	62,790
Commodity contracts	Current portion of derivative liability	(353)	(412)
Commodity contracts	Long-term derivative liability	(6,293)	(4,591)
		(6,646)	(5,003)
Total derivatives		$66,100	$57,787

	Years Ended December 31, 2010	2009	2008
Gain Recognized in Accumulated OCI	$ 16,542	$ 27,846	$23,956
(Gain) Loss Reclassified from Accumulated OCI into Income	$(27,364)	$(43,745)	$ 4,934

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 $27.4 million and $43.7 million for the years ended December 31, 2010 and 2009, respectively, and a loss of $4.9 million for the year ended December 31, 2008 on settled contracts covering natural gas and oil production for historical periods. These amounts 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, 2010, 2009 and 2008 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At December 31, 2010, 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]
2011	10,304,700	$6.977	$25,375
2012	6,074,700	$7.478	14,473
2013	4,124,500	$6.828	5,834
2014	1,729,700	$5.940	680
			$46,362

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes	Average Floor and Cap	Fair Value Asset/(Liability)
		(mmbtu)(1)	(per mmbtu) (1)	(in thousands)(2)
2011	Puts purchased	5,214,000	$6.543	$11,101
2011	Calls sold	5,214,000	$7.661	(129)
2012	Puts purchased	3,100,000	$6.117	4,692
2012	Calls sold	3,100,000	$7.343	(778)
2013	Puts purchased	5,241,000	$5.860	7,561
2013	Puts purchased	5,241,000	$7.043	(3,342)
2014	Calls sold	1,836,000	$5.711	2,619
2014	Puts purchased	1,836,000	$6.817	(1,721)
				$20,003

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes	Average Fixed Price	Fair Value Liability
	(Bbl)(1)	(per Bbl) (1)	(in thousands) (2)
2011	15,397	$87.637	$ (88)
2012	11,482	$87.228	(76)
2013	3,334	$87.560	(19)
			$(183)

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes	Average Floor and Cap	Fair Value Asset/(Liability)
		(Bbl) (1)	(per Bbl) (1)	(in thousands) (3)
2011	Puts purchased	9,759	$ 76.756	$ 20
2011	Calls sold	9,759	$100.891	(61)
2012	Puts purchased	7,366	$ 76.071	44
2012	Calls sold	7,366	$101.527	(77)
2013	Puts purchased	2,000	$ 76.073	16
2013	Calls sold	2,000	$102.523	(24)
				$ (82)
		Total net asset		$66,100

(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 the Partnership'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. The net unrealized derivative assets at December 31, 2010 and December 2009 were payable to the limited partners in the drilling partnerships and are included in the combined balance sheets as follows (in thousands):

	December 31, 2010	December 31, 2009
Current portion of derivative receivable from drilling partnerships	$ 138	$ 270
Long-term derivative receivable from drilling partnerships	4,669	2,841
Current portion of derivative payable to drilling partnerships	(30,797)	(22,382)
Long-term portion of derivative payable to drilling partnerships	(34,796)	(22,380)
	$(60,786)	$(41,651)

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 assumption 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 its 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, 2010 and 2009 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
December 31, 2010				
Commodity-based derivatives	$—	$66,100	$—	$66,100
December 31, 2009				
Commodity-based derivatives	$—	$57,787	$—	$57,787

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 non-recurring basis for the years ended December 31, 2010 and 2009 were as follows (in thousands):

	Years Ended December 31,			
	2010		2009	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$472	$472	$909	$909
Total	$472	$472	$909	$909

NOTE 8—CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

In the ordinary course of its business operations, 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 2013. Rental expense was $0.7 million, $0.7 million and $0.8 million for the years ended December 31, 2010, 2009 and 2008, respectively. Future minimum rental commitments for the next five years are as follows (in thousands):

Years Ended December 31:	
2011	$ 720
2012	482
2013	282
2014	141
2015	—
Thereafter	—
	$1,625

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. The Company may be required to subordinate a part of its net partnership revenues from the drilling partnerships to the benefit of the investor partners for an amount equal to at least 10% of their subscriptions, determined on a cumulative basis, in accordance with the terms of the partnership agreements. For the years ended December 31, 2010 and 2009, $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. The Company had no subordinated revenues during the year ended December 31, 2008.

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 investment drilling programs will invest approximately $35 million to drill 13 wells into the Marcellus Shale formation in Upshur County, West Virginia over the next twelve-month period.

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.

As of December 31, 2010, the Company is committed to expend approximately $65.1 million on drilling and completion expenditures, pipeline extensions, compressor station upgrades and processing facility upgrades.

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 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):

	Year Ended December 31,		
	2010 (Restated)	2009 (Restated)	2008 (Restated)
Gas and oil production			
Revenues	$ 93,050	$ 112,979	$ 127,083
Costs and expenses	(23,323)	(25,557)	(25,104)
Depreciation, depletion and amortization expense	(36,668)	(40,067)	(36,650)
Other asset impairment	(50,669)	(156,359)	—
Segment income (loss)	$ (17,610)	$(109,004)	$ 65,329
Well construction and completion			
Revenues	$ 206,802	$ 372,045	$ 415,036
Costs and expenses	(175,247)	(315,546)	(359,609)
Segment income	$ 31,555	$ 56,499	$ 55,427
Other partnership management[1]			
Revenues	$ 44,797	$ 52,252	$ 56,888
Costs and expenses	(31,043)	(34,599)	(29,752)
Depreciation, depletion and amortization expense	(4,090)	(3,645)	(3,131)
Segment income	$ 9,664	$ 14,008	$ 24,005
Reconciliation of segment income (loss) to net income (loss)			
Segment income (loss):			
Gas and oil production	$ (17,610)	$(109,004)	$ 65,329
Well construction and completion	31,555	56,499	55,427
Other partnership management	9,664	14,008	24,005
Total segment income (loss)	$ 23,609	$ (38,497)	$ 144,761
General and administrative[2]	(11,381)	(15,832)	(13,074)
Loss on asset sales[2]	(2,947)	—	—
Net income (loss)	$ 9,281	$ 54,329	$ 131,687
Capital expenditures			
Gas and oil production	$ 73,400	$ 89,389	$ 243,286
Well construction and completion	—	—	—
Other partnership management	17,200	9,900	17,297
Corporate and other	3,008	13	3,542
Total capital expenditures	$ 93,608	$ 99,302	$ 264,125

	December 31,	
	2010	2009
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	$593,368	$639,991
Well construction and completion	9,627	9,664
Other partnership management	37,677	36,433
Corporate and other	8,560	4,515
	$649,232	$690,603

(1) Includes revenues and expenses from well services, transportation, and administration and oversight that do not meet the quantitative threshold for reporting segment information.
(2) The Company notes that general and administrative expenses and loss on asset sales have not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

NOTE 11—SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserve Information. The preparation of the Company's natural gas and oil reserve estimates were completed in accordance with its prescribed internal control procedures by the Partnership's 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 the Partnership's and/or Old Atlas' annual Form 10-K for the years ended December 31, 2010, 2009 and 2008. For these periods, independent third-party reserve engineers were retained to prepare a report of proved reserves related to Old Atlas. 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 and Tennessee. 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 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, condensate 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, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of where deterministic or probabilistic methods are used for the estimation. Proved developed reserves are those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated unless such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating they are scheduled to be drilled within five years, unless specific circumstances, justify a longer time. In accordance with the prevailing accounting literature, the proved reserves quantities and future net cash flows as of December 31, 2010 were estimated using a 12-month average pricing based on the prices on the first day of each month during the year ended December 31, 2010.

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 is as follows (unaudited):

	Gas (Mcf)	Oil (Bbls)
Balance, January 1, 2008	190,874,642	1,972,359
Extensions, discoveries and other additions(1)	57,953,670	111,972
Sales of reserves in-place	(34,924)	(161)
Purchase of reserves in-place	3,461,987	794
Transfers to limited partnerships	(6,026,785)	8
Revisions(2)	(30,589,331)	(204,457)
Production	(12,002,314)	(154,681)
Balance, December 31, 2008	203,636,945	1,725,834
Extensions, discoveries and other additions(1)	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(1)	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
Proved developed reserves at:		
January 1, 2008	59,774,179	5,585
December 31, 2008	66,622,045	48,170
December 31, 2009	140,392,057	1,785,712
December 31, 2010	137,393,017	1,832,535
Proved undeveloped reserves at:		
January 1, 2008	131,100,463	1,966,774
December 31, 2008	137,014,900	1,677,664
December 31, 2009	43,262,907	37,010
December 31, 2010	38,671,986	—

(1) Principally includes increases of proved reserves due to the addition of Marcellus wells.

(2) Represents a decrease in the price of natural gas and oil compared from the year ended December 31, 2007 to the year ended December 31, 2008.
(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 discontinuation of drilling plans in the Clinton/Medina and Upper Devonian formations over the next five years.

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):

	Years Ended December 31,	
	2010	2009
Natural gas and oil properties:		
Proved properties	$ 847,101	$ 769,344
Unproved properties	42,520	40,189
Support equipment	8,138	5,792
	897,759	815,325
Accumulated depreciation, depletion and amortization[1]	$(419,375)	$(334,244)
Net capitalized costs	$ 478,384	$ 481,081

(1) During the year ended December 31, 2010, the Company recognized a $50.7 million 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 a $156.4 million impairment related to its shallow natural gas wells in the Upper Devonian Shale. Costs related to unproved properties are excluded from amortization as they are assessed for impairment.

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,		
	2010	2009	2008
Revenues	$ 93,050	$ 112,979	$127,083
Production costs	(23,323)	(25,557)	(25,104)
Depreciation, depletion and amortization	(36,668)	(40,067)	(36,650)
Long-lived asset impairment[1]	(50,669)	(156,359)	—
	$(17,610)	$(109,004)	$ 65,329

(1) During the year ended December 31, 2010, the Company recognized a $50.7 million 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 a $156.4 million impairment related to its shallow natural gas wells in the Upper Devonian Shale.

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, 2010 and 2009, and at year-end prices for the year ended December 31, 2008, adjusted only for fixed and determinable increases in natural gas and oil prices provided by contractual agreements. 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,		
	2010	2009	2008
Future cash inflows	$1,045,725	$ 993,206	$1,464,733
Future production costs	(464,392)	(429,630)	(550,179)
Future development costs	(35,357)	(75,011)	(155,055)
Future net cash flows	545,976	488,565	759,499
Less 10% annual discount for estimated timing of cash flows	(309,346)	(309,747)	(487,883)
Standardized measure of discounted future net cash flows	$ 236,630	$ 178,818	$ 271,616

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). Since the Company allocates taxable income to its owner, no recognition has been given to income taxes:

	Years Ended December 31,		
	2010	2009	2008
Balance, beginning of year	$178,818	$271,616	$ 400,204
Increase (decrease) in discounted future net cash flows:			
Sales and transfers of oil and gas, net of related costs	(51,522)	(38,316)	(58,281)
Net changes in prices and production costs	41,978	(95,712)	(120,320)
Revisions of previous quantity estimates	21,598	22,126	(1,208)
Development costs incurred	7,565	9,936	14,406
Changes in future development costs	(803)	(43,615)	(41,136)
Transfers to limited partnerships	(4,148)	(9,834)	(615)
Extensions, discoveries, and improved recovery less related costs	54,887	24,882	32,037
Purchases of reserves in-place	492	141	5,170
Sales of reserves in-place	(12,254)	(303)	(97)
Accretion of discount	17,882	25,298	39,639
Estimated settlement of asset retirement obligations	(6,074)	(2,252)	(3,745)
Estimated proceeds on disposals of well equipment	2,227	2,285	4,440
Changes in production rates (timing) and other	(14,016)	12,566	1,122
Outstanding, end of year	$236,630	$178,818	$ 271,616

ATLAS ENERGY E&P OPERATIONS

COMBINED BALANCE SHEETS
(in thousands)
(Unaudited)

	September 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 59,986	$ —
Accounts receivable	25,858	20,800
Advances from affiliates	2,676	—
Current portion of derivative asset	6,111	36,621
Prepaid expenses and other	7,246	8,585
Total current assets	101,877	66,006
Property, plant and equipment, net	526,634	508,484
Intangible assets, net	1,652	2,164
Goodwill, net	31,784	31,784
Long-term derivative asset	7,349	36,125
Long-term derivative receivable from drilling partnerships	—	4,669
	$669,296	$649,232
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 40,405	$ 45,957
Liabilities associated with drilling contracts	33,194	65,072
Current portion of derivative liability	—	353
Current portion of derivative payable to drilling partnerships	23,664	30,797
Accrued well drilling and completion costs	17,433	30,126
Accrued liabilities	20,576	11,283
Total current liabilities	135,272	183,588
Long-term derivative liability	—	6,293
Long-term derivative payable to drilling partnerships	19,808	34,796
Asset retirement obligation	44,840	42,673
Commitments and contingencies		
Equity:		
Equity	455,916	376,567
Accumulated other comprehensive income	13,460	5,315
Total equity	469,376	381,882
	$669,296	$649,232

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENT OF OPERATIONS
(in thousands)
(unaudited)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 (Restated)
Revenues:		
Gas and oil production	$ 51,654	$ 70,816
Well construction and completion	64,336	176,685
Gathering and processing	14,048	11,414
Administration and oversight	5,073	7,473
Well services	15,051	15,589
Total revenues	150,162	281,977
Costs and expenses:		
Gas and oil production	11,953	16,863
Well construction and completion	54,754	149,724
Gathering and processing	16,377	16,499
Well services	6,077	7,691
General and administrative	12,275	8,536
Depreciation, depletion and amortization	24,019	31,929
Total costs and expenses	125,455	231,242
Operating income	24,707	50,735
Loss on asset sales	—	(2,947)
Net income	$ 24,707	$ 47,788

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENT OF EQUITY
(in thousands)
(unaudited)

	Equity	Accumulated Other Comprehensive Income	Total
Balance at January 1, 2011	$376,567	$ 5,315	$381,882
Net investment from Atlas Energy, Inc.	54,642	—	54,642
Other comprehensive income	—	8,145	8,145
Net income	24,707	—	24,707
Balance at September 30, 2011	$455,916	$13,460	$469,376

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

COMBINED STATEMENTS OF CASH FLOWS
(in thousands)
(unaudited)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 (Restated)
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 24,707	$ 47,788
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	24,019	31,929
Non-cash loss on derivative value, net	43,472	—
Loss on asset sales	—	2,947
Changes in operating assets and liabilities:		
Accounts receivable and prepaid expenses and other	(6,533)	47,708
Accounts payable and accrued liabilities	(44,051)	(30,276)
Net cash provided by operating activities	41,614	100,096
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(36,270)	(70,716)
Other	—	210
Net cash used in investing activities	(36,270)	(70,506)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net investment received from Atlas Energy, Inc. (see Note 3)	54,642	—
Net distribution to Atlas Energy, Inc. (see Note 3)	—	(29,590)
Net cash provided by (used in) financing activities	54,642	(29,590)
Net change in cash and cash equivalents	59,986	—
Cash and cash equivalents, beginning of period	—	—
Cash and cash equivalents, end of period	$ 59,986	$ —

See accompanying notes to combined financial statements.

ATLAS ENERGY E&P OPERATIONS

NOTES TO COMBINED FINANCIAL STATEMENTS
September 30, 2011
(unaudited)

NOTE 1—BASIS OF PRESENTATION

On February 17, 2011, Atlas Energy, L.P. (the "Partnership"; NYSE: ATLS), a publicly-traded Delaware limited partnership formerly known as Atlas Pipeline Holdings, L.P., acquired certain producing natural gas and oil properties, an investment management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, and other assets (the "Transferred Business") from Atlas Energy, Inc. ("Old Atlas"), the former owner of its general partner. Atlas Energy E&P Operations (the "Company") consists of assets, liabilities, equity and operations of the subsidiaries of the Partnership which hold the natural gas and oil properties and direct investment business. The Partnership intends to transfer substantially all of the assets, liabilities and operations of the Company to Atlas Resource Partners, L.P. ("Atlas Resource Partners") and issue approximately 20% of Atlas Resource Partners' outstanding common limited partner interests to the Partnership's limited partners.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Combination

The combined balance sheets at September 30, 2011 and December 31, 2010 and the related combined statements of operations for the nine months ended September 30, 2011 and 2010 were derived from the separate records maintained by the Partnership 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, the Partnership'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 the Partnership, 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 Partnership operations have been identified in the combined statements as transactions between affiliates (see Note 3).

In accordance with prevailing accounting literature, management of the Partnership 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 the Partnership's partners' capital on its consolidated 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 Partnership's consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, the Partnership reflected the impact of the acquisition of the Transferred Business on its consolidated combined financial statements, from which the Company's combined financial statements were derived, 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 historical consolidated 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 historical consolidated combined statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners. The Transferred Business' historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by Old Atlas to the underlying business segments, including the aggregation of assets and liabilities now defined as the Predecessor. The Company has reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas 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 15% to 35%. 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.

Restatement – General and Administrative Expenses

The Company has restated its financial statements to reflect an allocation of general and administrative expenses related to the Transferred Business for the nine months ended September 30, 2010 in order to comply with the Securities and Exchange Commission's Staff Accounting Bulletin Topic 1, Paragraph B1 *"Allocation of Expenses and Related Disclosure in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity."* The Company has reviewed Old Atlas' general and administrative expense allocation methodology, which is based on the relative total assets of Old Atlas and the Transferred Business, for the Transferred Business' historical financial statements prior to the date of acquisition and believes the methodology is reasonable and reflects the approximate general and administrative costs of its underlying business segments.

The adjustment to net income for the nine months ended September 30, 2010 is summarized below (in thousands):

	Nine Months Ended September 30, 2010
Net income (loss), as previously reported	$56,324
General and administrative expenses	(8,536)
Net income (loss), as restated	$47,788

The impact of the restatement on the consolidated statements of cash flows is summarized below (in thousands):

	September 30, 2010	
	As Previously Reported	As Restated
Net income	$ 56,324	$ 47,788
Net cash provided by operating activities	108,632	100,096
Net distribution to Atlas Energy, Inc	38,126	29,590
Net cash used in financing activities	38,126	29,590

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 the Partnership in order to derive the historical period financial statements of the Company. Actual results could differ from those estimates.

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" beginning on page F-42). 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 combined 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 its 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, 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 7% 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 Partnership's reserve quantities include reserves in excess of its proportionate share of reserves in a drilling partnership which the Company may be unable to recover due to the drilling partnership's 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. There were no impairments of proved oil and gas properties recorded by the Company for the nine months ended September 30, 2011 and 2010.

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 oil and gas properties recorded by the Company for the nine months ended September 30, 2011 and 2010.

During the three months ended December 31, 2010, the Company recognized a $50.7 million asset impairment related to oil and gas properties within property, plant and equipment on its combined balance sheet for its shallow natural gas wells in Tennessee and Ohio. This impairment related to the carrying amount of these oil and gas properties being in excess of the Company's estimate of their fair value at December 31, 2010. The estimate of fair value of these oil and gas 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 September 30, 2011 and December 31, 2010 (in thousands):

	September 30, 2011	December 31, 2010	Estimated Useful Lives In Years
Gross Carrying Amount	$ 14,344	$ 14,344	1 – 13
Accumulated Amortization	(12,692)	(12,180)	
Net Carrying Amount	$ 1,652	$ 2,164	

Amortization expense on intangible assets was $0.5 million and $0.5 million for the nine months ended September 30, 2011 and 2010, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2011 – $0.7 million; 2012 – $0.2 million; 2013 – $0.2 million; 2014 – $0.1 million; and 2015 – $0.1 million.

Goodwill

At September 30, 2011 and December 31, 2010, the Company had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions.

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, management must apply judgment in determining the estimated fair value of these reporting units. 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. The fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in its industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate the goodwill at least annually or when impairment indicators arise.

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 180 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 natural gas liquids 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. 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 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). Generally, the Company's sales contracts are based on pricing provisions that are tied to a market index, which is generally fixed 2 business days prior to the commencement of the production month, with certain fixed adjustments based on proximity to gathering and transmission lines and the quality of its natural gas. The Company had unbilled revenues at September 30, 2011 and December 31, 2010 of $13.7 million and $20.8 million, respectively, which were included in accounts receivable within its combined balance sheets.

Comprehensive Income

Comprehensive income includes net income 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. These changes, other than net income, are referred to as "other comprehensive income" and for the Company includes changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges. The following table sets forth the calculation of the Company's comprehensive income (in thousands):

	Nine Months Ended September 30,	
	2011	2010
Net income	$24,707	$ 47,788
Other comprehensive income (loss):		
Changes in fair value of derivative instruments accounted for as cash flow hedges	17,733	31,341
Less: reclassification adjustment for realized gains in net income	(9,588)	(23,902)
Total other comprehensive income (loss)	8,145	7,439
Comprehensive income attributable to owner	$32,852	$ 55,227

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 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 permit an entity to first assess qualitative factors in determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in Topic 350. The "more likely than not" threshold is defined as having a likelihood of more than 50 percent. If, after assessing the totality of events or circumstances, an entity determines it is not "more likely than not" that the fair value of a reporting unit is less than its carrying amount, then 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 for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. An entity may resume performing the qualitative assessment in any subsequent period. Update 2011-08 will be effective for fiscal years beginning after December 15, 2011, with early adoption permitted. The Partnership 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 June 2011, the FASB issued Accounting Standards Update 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income ("Update 2011-05"). Update 2011-05 amends the FASB Accounting Standards Codification to provide an entity with 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. These changes apply to both annual and interim financial statements. Update 2011-05 will be effective for public entities' fiscal years, and interim periods within those years, beginning after December 15, 2011. The Company will apply the requirements of Update 2011-05 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 IFRSs. 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 Partnership 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—ACQUISITION FROM ATLAS ENERGY, INC.

On February 17, 2011, the Partnership acquired the Transferred Business, including the assets and liabilities of the Company, from Old Atlas, the former parent of its general partner, which included the following assets:

- Old Atlas' investment management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which the Company will fund 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 will be a developer and producer;
- all of the ownership interests in Atlas Energy GP, LLC, the Partnership'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, the Partnership issued approximately 23.4 million of its common limited partner units and paid $30.0 million in cash consideration. Based on the Partnership's February 17, 2011 common unit closing price of $15.92, the common units issued to Old Atlas were valued at approximately $372.2 million. In connection with the transaction, the Partnership also received $124.7 million with respect to a contractual cash transaction adjustment from Old Atlas related to certain liabilities assumed by the Partnership. Including the cash transaction adjustment, the net book value of the assets acquired was approximately $528.7 million.

Concurrent with the Partnership's acquisition of assets, including the assets and liabilities of the Company, Old Atlas completed its merger with Chevron Corporation ("Chevron"), whereby Old Atlas became a wholly owned subsidiary of Chevron.

Also concurrent with the Partnership's acquisition of assets and immediately preceding Old Atlas' merger with Chevron, Atlas Pipeline Partners, L.P. ("APL"), a publicly-traded limited partnership (NYSE: APL) in which the Partnership owns a 2% general partner interest, all of the incentive distribution rights, and an approximate 10.7% common limited partner interest at September 30, 2011, completed its sale to Old Atlas 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.

In accordance with prevailing accounting literature, management of the Partnership determined that the acquisition of the Transferred Business constituted a transaction between entities under common control (see Note 2). As such, the Partnership recognized the assets acquired and liabilities assumed at historical carrying value at the date of acquisition, with the difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital on its consolidated combined balance sheet. The Partnership recognized a non-cash decrease of $254.5 million in partners' capital on its consolidated combined balance sheet based on the excess net book value above the value of the consideration paid to Old Atlas. The following table presents the historical carrying value of the assets acquired and liabilities assumed by the Partnership, including the effect of cash transaction adjustments, as of February 17, 2011 (in thousands):

Cash	$159,180
Accounts receivable	18,090
Accounts receivable—affiliate	45,682
Prepaid expenses and other	6,955
Total current assets	229,907
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	$800,839
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	$528,704

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

NOTE 4—PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2011	December 31, 2010	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$ 49,780	$ 46,495	
Pre-development costs	16,505	2,337	
Wells and related equipment	815,623	798,269	
Total proved properties	881,908	847,101	
Unproved properties	42,843	42,520	
Support equipment	9,655	8,138	
Total natural gas and oil properties	934,406	897,759	
Pipelines, processing and compression facilities	32,131	30,072	2 – 40
Rights of way	84	84	20 – 40
Land, buildings and improvements	6,004	5,632	3 – 40
Other	6,165	4,727	3 – 10
	978,790	938,274	
Less—accumulated depreciation, depletion and amortization	(452,156)	(429,790)	
	$ 526,634	$ 508,484	

NOTE 5—ASSET RETIREMENT OBLIGATIONS

The Company recognizes an estimated liability for the plugging and abandonment of its oil and gas 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 oil and gas 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):

	Nine Months Ended September 30,	
	2011	2010
Asset retirement obligations, beginning of period	$42,673	$36,599
Liabilities incurred	369	286
Liabilities settled	(150)	(193)
Accretion expense	1,948	1,650
Asset retirement obligations, end of period	$44,840	$38,342

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 its commodity 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 is sold. Under 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 Company's 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 for 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 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 a net derivative asset of $13.5 million and $66.1 million at September 30, 2011 and December 31, 2010, respectively. Of the $13.5 million of net gain in accumulated other comprehensive income within equity on the Company's combined balance sheet related to derivatives at September 30, 2011, if the fair values of the instruments remain at current market values, the Company will reclassify $6.1 million of gains to gas and oil production revenues to its combined statements of operations over the next twelve-month period as these contracts expire. Aggregate gains of gas and oil production revenues of $7.4 million will be reclassified to the Company's combined statements of operations in later periods as these 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 derivative instruments as of September 30, 2011 and December 31, 2010, as well as the gain or loss recognized in the combined statements of operations for effective derivative instruments for the nine months ended September 30, 2011 and 2010:

Contract Type	Balance Sheet Location	September 30, 2011	December 31, 2010
Commodity contracts	Current portion of derivative asset	$ 6,252	$36,621
Commodity contracts	Long-term derivative asset	11,099	36,125
		17,351	72,746
Commodity contracts	Current portion of derivative liability	(142)	(353)
Commodity contracts	Long-term derivative liability	(3,749)	(6,293)
		(3,891)	(6,646)
Total derivatives		$13,460	$66,100

	Nine Months Ended September 30,	
	2011	2010
Gain (Loss) Recognized in Accumulated OCI	$17,733	$ 31,341
(Gain) Loss Reclassified from Accumulated OCI into Income	$ (9,588)	$(23,902)

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 $9.6 million and $23.9 million for the nine months ended September 30, 2011 and 2010, 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 nine months ended September 30, 2011 and 2010 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At September 30, 2011, the Company had the following commodity derivatives:

Natural Gas Fixed Price Swaps

Production Period Ending December 31,	Volumes	Average Fixed Price	Fair Value Asset
	(mmbtu)(1)	(per mmbtu)(1)	(in thousands)(2)
2011	1,560,000	$4.484	$1,073
2012	5,520,000	$5.000	4,175
2013	3,120,000	$5.288	1,497
2014	2,880,000	$5.590	1,286
2015	2,880,000	$5.861	1,312
			$9,343

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes	Average Floor and Cap	Fair Value Asset/(Liability)
		(mmbtu)(1)	(per mmbtu)(1)	(in thousands)(2)
2011	Puts purchased	810,000	$3.933	$ 187
2011	Calls sold	810,000	$5.584	—
2012	Puts purchased	1,920,000	$4.250	751
2012	Calls sold	1,920,000	$6.084	(89)
2013	Puts purchased	3,120,000	$4.750	1,738
2013	Calls sold	3,120,000	$6.065	(729)
2014	Puts purchased	1,440,000	$4.700	805
2014	Calls sold	1,440,000	$5.930	(767)
2015	Puts purchased	1,440,000	$4.900	993
2015	Calls sold	1,440,000	$6.230	(1,007)
				$ 1,882

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes	Average Floor and Cap	Fair Value Asset/(Liability)
		(Bbl)(1)	(per Bbl)(1)	(in thousands)(3)
2011	Puts purchased	15,000	$ 90.000	$ 205
2011	Calls sold	15,000	$125.312	(1)
2012	Puts purchased	60,000	$ 90.000	1,053
2012	Calls sold	60,000	$117.912	(190)
2013	Puts purchased	60,000	$ 90.000	1,269
2013	Calls sold	60,000	$116.396	(479)
2014	Puts purchased	24,000	$ 80.000	492
2014	Calls sold	24,000	$121.250	(287)
2015	Puts purchased	24,000	$ 80.000	515
2015	Calls sold	24,000	$120.750	(342)
				$ 2,235
		Total net asset		$13,460

(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 the Partnership'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 acquisition of the Transferred Business, Old Atlas monetized all of its derivative instruments, including those related to the future natural gas and oil production of the Transferred Business. Old Atlas also monetized derivative instruments which were specifically related to the future natural gas and oil production of the limited partners of the drilling partnerships. 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 September 30, 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 consolidated combined balance sheets as follows (in thousands):

	September 30, 2011	December 31, 2010
Current portion of derivative receivable from Partnerships . . .	$ —	$ 138
Long-term derivative receivable from Partnerships	—	4,669
Current portion of derivative payable to Partnerships	(23,664)	(30,797)
Long-term portion of derivative payable to Partnerships	(19,808)	(34,796)
	$(43,472)	$(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 its 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 September 30, 2011 and December 31, 2010 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
September 30, 2011				
Commodity-based derivatives	$—	$13,460	$—	$13,460
December 31, 2010				
Commodity-based derivatives	$—	$66,100	$—	$66,100

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 non-recurring basis for the nine months ended September 30, 2011 and 2010 were as follows (in thousands):

	Nine Months Ended September 30,			
	2011		2010	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$369	$369	$286	$286
Total	$369	$369	$286	$286

NOTE 8—CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

In the ordinary course of its business operations, 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 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. The Company may be required to subordinate a part of its net partnership revenues from the drilling partnerships to the benefit of the investor partners for an amount equal to at least 10% of their subscriptions, determined on a cumulative basis, in accordance with the terms of the partnership agreements. For the nine months ended September 30, 2011 and 2010, $3.6 million and $8.9 million, respectively, of the Company's revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the drilling partnerships.

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 investment drilling programs will invest approximately $35 million to drill 13 wells into the Marcellus Shale formation in Upshur County, West Virginia over the next twelve-month period.

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.

As of September 30, 2011, the Company is committed to expend approximately $1.5 million on drilling and completion expenditures, pipeline extensions, compressor station upgrades and processing facility upgrades.

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):

	Nine Months Ended September 30,	
	2011	2010 (Restated)
Gas and oil production		
Revenues	$ 51,654	$ 70,816
Costs and expenses	(11,953)	(16,863)
Depreciation, depletion and amortization expense	(20,626)	(28,052)
Segment income	$ 19,075	$ 25,901
Well construction and completion		
Revenues	$ 64,336	$ 176,685
Costs and expenses	(54,754)	(149,724)
Segment income	$ 9,582	$ 26,961
Other partnership management[1]		
Revenues	$ 34,172	$ 34,476
Costs and expenses	(22,454)	(24,190)
Depreciation, depletion and amortization expense	(3,393)	(3,877)
Segment income (loss)	$ 8,325	$ 6,409
Reconciliation of segment income (loss) to net income		
Segment income (loss):		
Gas and oil production	$ 19,075	$ 25,901
Well construction and completion	9,582	26,961
Other partnership management	8,325	6,409
Net segment income	36,982	59,271
General and administrative expenses[2]	(12,275)	(8,536)
Loss on asset sales[2]	—	(2,947)
Net segment income	$ 24,707	$ 47,788
Capital expenditures		
Gas and oil production	$ 29,053	$ 57,671
Well construction and completion	—	—
Other partnership management	3,207	10,623
Corporate and other	4,010	2,422
Total capital expenditures	$ 36,270	$ 70,716

	September 30, 2011	December 31, 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	$550,764	$593,368
Well construction and completion	6,961	9,627
Other partnership management	45,449	37,677
Corporate and other	66,122	8,560
	$669,296	$649,232

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

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

Annex A

FORM OF

AMENDED AND RESTATED

AGREEMENT OF LIMITED PARTNERSHIP

OF

ATLAS RESOURCE PARTNERS, L.P.

TABLE OF CONTENTS

AMENDED AND RESTATED
AGREEMENT OF LIMITED PARTNERSHIP
OF
ATLAS RESOURCE PARTNERS, L.P.

This AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF ATLAS RESOURCE PARTNERS, L.P., dated as of [•], is entered into by and between ATLAS RESOURCE PARTNERS GP, LLC, a Delaware limited liability company, as the General Partner, and ATLAS ENERGY, L.P., a Delaware limited partnership, as the Organizational Limited Partner, together with any other Persons who become Partners in the Partnership or parties hereto as provided herein. In consideration of the covenants, conditions and agreements contained herein, the parties hereto hereby agree as follows:

ARTICLE I

DEFINITIONS

SECTION 1.1. *Definitions*.

The following definitions shall be for all purposes, unless otherwise clearly indicated to the contrary, applied to the terms used in this Agreement.

"*Acquisition*" means any transaction in which any Group Member acquires (through an asset acquisition, merger, stock acquisition or other form of investment) control over all or a portion of the assets, properties or business of another Person for the purpose of increasing the asset base of the Partnership Group from the asset base of the Partnership Group existing immediately prior to such transaction.

"*Additional Book Basis*" means the portion of any remaining Carrying Value of an Adjusted Property that is attributable to positive adjustments made to such Carrying Value as a result of Book-Up Events. For purposes of determining the extent that Carrying Value constitutes Additional Book Basis:

(a) Any negative adjustment made to the Carrying Value of an Adjusted Property as a result of either a Book-Down Event or a Book-Up Event shall first be deemed to offset or decrease that portion of the Carrying Value of such Adjusted Property that is attributable to any prior positive adjustments made thereto pursuant to a Book-Down Event or a Book-Up Event.

(b) If Carrying Value that constitutes Additional Book Basis is reduced as a result of a Book-Down Event and the Carrying Value of other property is increased as a result of such Book-Down Event, an allocable portion of any such increase in Carrying Value shall be treated as Additional Book Basis; *provided* that the amount treated as Additional Book Basis as a result of such Book-Down Event shall not exceed the amount by which the Aggregate Remaining Net Positive Adjustments after such Book-Down Event exceeds the remaining Additional Book Basis attributable to all of the Partnership's Adjusted Property after such Book-Down Event (determined without regard to the application of this clause (b) to such Book-Down Event).

"*Additional Book Basis Derivative Items*" means any Book Basis Derivative Items that are computed with reference to Additional Book Basis. To the extent that the Additional Book Basis attributable to all of the Partnership's Adjusted Property as of the beginning of any taxable period exceeds the Aggregate Remaining Net Positive Adjustments as of the beginning of such period (the "*Excess Additional Book Basis*"), the Additional Book Basis Derivative Items for such period shall be reduced by the amount that bears the same ratio to the amount of Additional Book Basis Derivative Items determined without regard to this sentence as the Excess Additional Book Basis bears to the Additional Book Basis as of the beginning of such period.

"*Additional Limited Partner*" means a Person admitted to the Partnership as a Limited Partner pursuant to Section 4.5(d) and who is shown as such on the books and records of the Partnership.

"*Adjusted Capital Account*" means the Capital Account maintained for each Partner as of the end of each taxable year of the Partnership, (a) increased by any amounts that such Partner is obligated to restore under the standards set by Treasury Regulation Section 1.704-1(b)(2)(ii)(c) (or is deemed obligated to restore under Treasury Regulation Sections 1.704-2(g) and 1.704-2(i)(5)) and (b) decreased by (i) the amount of all adjustments that, as of the end of such taxable year, reasonably are expected to be made to such Partner's Capital Account under Treasury Regulation Section 1.704-1(b)(2)(iv)(k) for depletion allowances with respect to oil and gas properties of the Partnership, (ii) the amount of all losses and deductions that, as of the end of such taxable year, reasonably are expected to be allocated to such Partner in subsequent years pursuant to Sections 704(e)(2) and 706(d) of the Code and Treasury Regulation Section 1.751-1(b)(2)(ii), and (iii) the amount of all distributions that, as of the end of such taxable year, reasonably are expected to be made to such Partner in subsequent years in accordance with the terms of this Agreement or otherwise to the extent they exceed offsetting increases to such Partner's Capital Account that are reasonably expected to occur during (or prior to) the year in which such distributions are reasonably expected to be made (other than increases as a result of a minimum gain chargeback pursuant to Section 6.1(d)(i) or 6.1(d)(ii)). The foregoing definition of Adjusted Capital Account is intended to comply with the provisions of Treasury Regulation Section 1.704-1(b)(2)(ii)(d) and shall be interpreted consistently therewith. The "Adjusted Capital Account" of a Partner in respect of a Class A Unit, a Common Unit or an Incentive Distribution Right or any other Partnership Interest shall be the amount that such Adjusted Capital Account would be if such Class A Unit, Common Unit, Incentive Distribution Right or other Partnership Interest were the only interest in the Partnership held by such Partner from and after the date on which such Class A Unit, Common Unit, Incentive Distribution Right or other Partnership Interest was first issued.

"*A1adjusted Operating Surplus*" means, with respect to any period, (a) Operating Surplus generated with respect to such period (b) less (i) the amount of any net increase in Working Capital Borrowings with respect to such period and (ii) the amount of any net decrease in cash reserves for Operating Expenditures with respect to such period not relating to an Operating Expenditure made with respect to such period (it being understood that, in calculating the amount of Adjusted Operating Surplus in respect of any Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash reserves for Operating Expenditures by such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100), and (c) plus (i) the amount of any net decrease in Working Capital Borrowings with respect to such period, (ii) the amount of any net increase in cash reserves for Operating Expenditures with respect to such period required by any debt instrument for the repayment of principal, interest or premium (it being understood that, in calculating the amount of Adjusted Operating Surplus in respect of any Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash reserves for Operating Expenditures by such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100) and (iii) the amount of any net decrease made in subsequent periods in cash reserves for Operating Expenditures initially established with respect to such period to the extent such decrease results in a reduction in Adjusted Operating Surplus in subsequent periods pursuant to clause (b)(ii) above. Adjusted Operating Surplus does not include that portion of Operating Surplus included in clause (a)(i) of the definition of Operating Surplus.

"*Adjusted Property*" means any property the Carrying Value of which has been adjusted pursuant to Section 5.4(d)(i) or 5.4(d)(ii).

"*Affiliate*" means, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries controls, is controlled by or is under common control with, the Person in question. As used herein, the term "*control*" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

"*Aggregate Quantity of IDR Reset Common Units*" has the meaning assigned to such term in Section 5.9(a).

"*Aggregate Remaining Net Positive Adjustments*" means, as of the end of any taxable period, the sum of the Remaining Net Positive Adjustments of all the Partners.

"*Agreed Allocation*" means any allocation, other than a Required Allocation, of an item of income, gain, loss or deduction pursuant to the provisions of Section 6.1, including a Curative Allocation (if appropriate to the context in which the term "Agreed Allocation" is used).

"*Agreed Value*" of any Contributed Property means the fair market value of such property or other consideration at the time of contribution and in the case of an Adjusted Property, the fair market value of such Adjusted Property on the date of the revaluation event as described in Section 5.4(d), in both cases as determined by the General Partner. The General Partner shall use such method as it determines to be appropriate to allocate the aggregate Agreed Value of Contributed Properties contributed to the Partnership in a single or integrated transaction among each separate property on a basis proportional to the fair market value of each Contributed Property.

"*Agreement*" means this Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P., as it may be amended, supplemented or restated from time to time.

"*Associate*" means, when used to indicate a relationship with any Person, (a) any corporation or organization of which such Person is a director, officer, manager, member, general partner or managing member or is, directly or indirectly, the owner of 20% or more of any class of voting stock or other voting interest; (b) any trust or other estate in which such Person has at least a 20% beneficial interest or as to which such Person serves as trustee or in a similar fiduciary capacity; and (c) any relative or spouse of such Person, or any relative of such spouse, who has the same principal residence as such Person.

"*Available Cash*" means, with respect to any Quarter ending prior to the Liquidation Date,

(a) the sum of:

(i) all cash and cash equivalents (including amounts available for working capital purposes under a credit facility, commercial paper facility or other similar financing arrangement) of the Partnership Group on hand at the end of such Quarter (it being understood that, in calculating the amount of Available Cash in respect of a Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash and cash equivalents of such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100); and

(ii) if the General Partner so determines in its sole discretion, all or any portion of additional cash and cash equivalents of the Partnership Group on hand on the date of determination of Available Cash with respect to such Quarter resulting from borrowings (including Working Capital Borrowings) made subsequent to the end of such Quarter (it being understood that, in calculating the amount of Available Cash in respect of a Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such additional cash and cash equivalents of such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100);

(b) *less* the amount of any cash reserves established by the General Partner for the Partnership Group (it being understood that, in calculating the amount of Available Cash in respect of a Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash reserves established for such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100) on the date of determination of Available Cash with respect to such Quarter, to:

(i) provide for the proper conduct of the business of the Partnership Group (including reserves for working capital, operating expenses, future capital expenditures, potential acquisitions and for anticipated future credit needs of the Partnership Group);

(ii) comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which any Group Member is a party or by which it is bound or its assets are subject; or

(iii) provide funds for distributions pursuant to Section 6.4 or 6.5 with respect to any one or more of the next four Quarters; or

(iv) provide funds for distributions with respect to the Incentive Distribution Rights;

provided, *however*, that the General Partner may not establish cash reserves pursuant to subclause (iii) above if the effect of such reserves would be that the Partnership is unable to distribute the Minimum Quarterly Distribution on all Common Units and Class A Units with respect to such Quarter; and *provided further*, that disbursements made by a Group Member or cash reserves established, increased or reduced after the end of such Quarter but on or before the date of determination of Available Cash with respect to such Quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining Available Cash, within such Quarter if the General Partner so determines.

Notwithstanding the foregoing, "*Available Cash*" with respect to the Quarter in which the Liquidation Date occurs and any subsequent Quarter shall equal zero.

"*Board of Directors*" means (i) if the General Partner is a corporation or a limited liability company, the General Partner's board of directors or board of managers, as applicable, and (ii) if the General Partner is a limited partnership, the board of directors or board of managers, as applicable, of the general partner of the General Partner.

"*Book Basis Derivative Items*" means any item of income, deduction, gain or loss included in the determination of Net Income or Net Loss that is computed with reference to the Carrying Value of an Adjusted Property (e.g., depreciation, depletion, or gain or loss with respect to an Adjusted Property).

"*Book-Down Event*" means an event that triggers a negative adjustment to the Capital Accounts of the Partners pursuant to Section 5.4(d).

"*Book-Tax Disparity*" means with respect to any item of Contributed Property or Adjusted Property, as of the date of any determination, the difference between the Carrying Value of such Contributed Property or Adjusted Property and the adjusted basis thereof for U.S. federal income tax purposes as of such date. A Partner's share of the Partnership's Book-Tax Disparities in all of its Contributed Property and Adjusted Property will be reflected by the difference between such Partner's Capital Account balance as maintained pursuant to Section 5.4 and the hypothetical balance of such Partner's Capital Account computed as if it had been maintained strictly in accordance with U.S. federal income tax accounting principles.

"*Book-Up Event*" means an event that triggers a positive adjustment to the Capital Accounts of the Partners pursuant to Section 5.4(d).

"*Business Day*" means Monday through Friday of each week, except that a legal holiday recognized as such by the government of the United States of America or the Commonwealth of Pennsylvania shall not be regarded as a Business Day.

"*Capital Account*" means the capital account maintained for a Partner pursuant to Section 5.4. The "Capital Account" of a Partner in respect of a Class A Unit, a Common Unit, an Incentive Distribution Right or any other Partnership Interest shall be the amount that such Capital Account would be if such Class A Unit, Common Unit, Incentive Distribution Right or other Partnership Interest were the only interest in the Partnership held by a Partner from and after the date on which such Class A Unit, Common Unit, Incentive Distribution Right or other Partnership Interest was first issued.

"*Capital Contribution*" means any cash, cash equivalents or the Net Agreed Value of Contributed Property that a Partner contributes to the Partnership pursuant to this Agreement or the Separation Agreement or that is contributed or deemed contributed to the Partnership on behalf of a Partner (including, in the case of an underwritten offering of Partnership Interests, the amount of any underwriting discounts or commissions).

"*Capital Improvement*" means any (a) addition or improvement to the capital assets owned by any Group Member, (b) acquisition (through an asset acquisition, merger, stock acquisition or other form of investment) of existing, or construction of new or improvement or replacement of existing, capital assets (including undeveloped leasehold acreage, properties containing estimated proved reserves (whether or not producing) and other similar assets) or (c) capital contribution by a Group Member to a Person that is not a Subsidiary in which a Group Member has an equity interest, or after such capital contribution will have an equity interest, to fund such Group Member's pro rata share of the cost of the addition or improvement to, the acquisition of existing, the construction of new or the improvement or replacement of existing capital assets by such Person, in each case if such addition, improvement, replacement, acquisition or construction is made to increase the asset base of the Partnership Group, in the case of clauses (a) and (b), or such Person, in the case of clause (c), from the asset base of the Partnership Group or such Person, as the case may be, existing immediately prior to such addition, improvement, replacement, acquisition or construction.

"*Capital Surplus*" has the meaning assigned to such term in Section 6.3(a).

"*Carrying Value*" means (a) with respect to a Contributed Property or Adjusted Property, the Agreed Value of such property reduced (but not below zero) by all depreciation, Simulated Depletion, amortization and cost recovery deductions charged to the Partners' Capital Accounts in respect of such property, and (b) with respect to any other Partnership property, the adjusted basis of such property for U.S. federal income tax purposes, all as of the time of determination. The Carrying Value of any property shall be adjusted from time to time in accordance with Sections 5.4(d)(i) and 5.4(d)(ii) and to reflect changes, additions or other adjustments to the Carrying Value for dispositions and acquisitions of Partnership properties, as deemed appropriate by the General Partner.

"*Cause*" means a court of competent jurisdiction has entered a final, non-appealable judgment finding the General Partner liable for actual fraud or willful misconduct in its capacity as a general partner of the Partnership.

"*Certificate*" means a certificate in such form (including in global form if permitted by applicable rules and regulations) as may be adopted by the General Partner, issued by the Partnership evidencing ownership of one or more Common Units or a certificate, in such form as may be adopted by the General Partner, issued by the Partnership evidencing ownership of one or more other Partnership Interests.

"*Certificate of Limited Partnership*" means the Certificate of Limited Partnership of the Partnership filed with the Secretary of State of the State of Delaware as referenced in Section 2.1, as such Certificate of Limited Partnership may be amended, supplemented or restated from time to time.

"*Citizenship Eligibility Trigger*" has the meaning assigned to such term in Section 4.9(a)(ii).

"*claim*" has the meaning assigned to such term in Section 7.13(c).

"*Class A Unit*" means a fractional part of the General Partner Interest having the rights and obligations specified with respect to the General Partner Interest. A Class A Unit is not a Unit.

"*Closing Date*" means March 13, 2012.

"*Closing Price*" has the meaning assigned to such term in Section 15.1(a).

"*Code*" means the Internal Revenue Code of 1986, as amended and in effect from time to time. Any reference herein to a specific section or sections of the Code shall be deemed to include a reference to any corresponding provision of any successor law.

"*Combined Interest*" has the meaning assigned to such term in Section 11.3(a).

"*Commences Commercial Service*" and "*Commencement of Commercial Service*" shall mean the date on which a Capital Improvement or replacement asset begins producing in paying quantities or is first put into commercial service following completion of construction, acquisition, development and testing, as applicable.

"*Commission*" means the United States Securities and Exchange Commission.

"*Common Unit*" means a Partnership Interest representing a fractional part of the Partnership Interests of all Limited Partners and of the General Partner (exclusive of its interest as a holder of the General Partner Interest, Class A Units and Incentive Distribution Rights) and having the rights and obligations specified with respect to Common Units in this Agreement.

"*Conflicts Committee*" means a committee of the Board of Directors composed of one or more directors, each of whom (a) is not an officer or employee of the General Partner, (b) is not an officer, director or employee of any Affiliate of the General Partner, (c) is not a holder of any ownership interest in the General Partner or the Partnership, other than Common Units or other awards granted to such director under the Partnership's equity compensation plans, and (d) meets the independence standards required of directors who serve on an audit committee of a board of directors established by the Securities Exchange Act and the rules and regulations of the Commission thereunder and by the National Securities Exchange on which the Common Units are listed or admitted for trading.

"*Contributed Property*" means each property or other asset, in such form as may be permitted by the Delaware Act, but excluding cash, contributed to the Partnership (or deemed contributed to a new partnership on termination of the Partnership pursuant to Section 708 of the Code). Once the Carrying Value of a Contributed Property is adjusted pursuant to Section 5.4(d), such property shall no longer constitute a Contributed Property but shall be deemed an Adjusted Property.

"*Curative Allocation*" means any allocation of an item of income, gain, deduction, loss or credit pursuant to the provisions of Section 6.1(d)(x).

"*Current Market Price*" has the meaning assigned to such term in Section 15.1(a).

"*Delaware Act*" means the Delaware Revised Uniform Limited Partnership Act, 6 Del. C. Section 17-101, *et seq.*, as amended, supplemented or restated from time to time, and any successor to such statute.

"*Departing General Partner*" means a former general partner of the Partnership from and after the effective date of any withdrawal or removal of such former general partner pursuant to Section 11.1 or 11.2.

"*Economic Risk of Loss*" has the meaning set forth in Treasury Regulation Section 1.752-2(a).

"*Eligibility Certificate*" has the meaning assigned to such term in Section 4.9(b).

"*Eligible Holder*" means a Limited Partner whose (a) U.S. federal income tax status would not, in the determination of the General Partner, have the material adverse effect described in Section 4.9(a)(i) or (b) nationality, citizenship or other related status would not, in the determination of the General Partner, create a substantial risk of cancellation or forfeiture as described in Section 4.9(a)(ii).

"*Estimated Maintenance Capital Expenditures*" means an estimate made in good faith by the Board of Directors of the average quarterly Maintenance Capital Expenditures that the Partnership will need to incur over the long term to maintain the levels of oil and natural gas production of the Partnership Group existing at the time the estimate is made. The Board of Directors will be permitted to make such estimate in any manner it determines reasonable. The estimate will be made at least annually and whenever an event occurs that is likely to result in a material adjustment to the amount of future Estimated Maintenance Capital Expenditures. The Partnership shall disclose to its Partners any change in the amount of Estimated Maintenance Capital Expenditures in its reports made in accordance with Section 8.3 to the extent not previously disclosed. Any adjustments to Estimated Maintenance Capital Expenditures shall be prospective only.

"*Event of Withdrawal*" has the meaning assigned to such term in Section 11.1(a).

"*Exchange Act*" means the U.S. Securities Exchange Act of 1934, as amended, supplemented or restated from time to time and any successor to such statute.

"*Expansion Capital Expenditures*" means cash expenditures for Acquisitions or Capital Improvements. Expansion Capital Expenditures shall include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance the construction of a Capital Improvement and paid in respect of the period beginning on the date that a Group Member enters into a binding obligation to commence construction or development of a Capital Improvement and ending on the earlier to occur of the date that such Capital Improvement Commences Commercial Service or the date that such Capital Improvement is abandoned or disposed of. Debt incurred to fund such construction period interest payments or to fund distributions in respect of equity issued (including incremental Incentive Distributions related thereto) to fund the construction of a Capital Improvement as described in clause (a)(iv) of the definition of Operating Surplus shall also be deemed to be debt incurred to finance the construction of a Capital Improvement. Where capital expenditures are made in part for Expansion Capital Expenditures and in part for other purposes, the General Partner shall determine the allocation between the amounts paid for each.

"*First Liquidation Target Amount*" has the meaning assigned to such term in Section 6.1(c)(i)(C).

"*First Target Distribution*" means $0.46 per Common Unit per Quarter and $0.46 per Class A Unit per Quarter (or, with respect to periods of less than a full fiscal quarter, it means the product of $0.46 multiplied by a fraction, the numerator of which is the number of days in such period and the denominator of which is the total number of days in such fiscal quarter), subject to adjustment in accordance with Sections 5.9, 6.6 and 6.8.

"*General Partner*" means Atlas Resource Partners GP, LLC, a Delaware limited liability company, and its successors and permitted assigns that are admitted to the Partnership as general partner of the Partnership, in its capacity as general partner of the Partnership (except as the context otherwise requires).

"*General Partner Interest*" means the ownership interest of the General Partner in the Partnership (in its capacity as a general partner without reference to any Limited Partner Interest, including Incentive Distribution Rights or Common Units, held by it), which ownership interest is evidenced by Class A Units, and includes any and all benefits to which the General Partner is entitled as provided in this Agreement, together with all obligations of the General Partner to comply with the terms and provisions of this Agreement.

"Gross Liability Value" means, with respect to any Liability of the Partnership described in Treasury Regulation Section 1.752-7(b)(3)(i), the amount of cash that a willing assignor would pay to a willing assignee to assume such Liability in an arm's-length transaction.

"*Group*" means a Person that, with or through any of its Affiliates or Associates, has any contract, agreement, arrangement, understanding or relationship for the purpose of acquiring, holding, voting (except voting pursuant to a revocable proxy or consent given to such Person in response to a proxy or consent solicitation made to 10 or more Persons), exercising investment power or disposing of any Partnership Interests with any other Person that beneficially owns, or whose Affiliates or Associates beneficially own, directly or indirectly, Partnership Interests.

"*Group Member*" means a member of the Partnership Group.

"*Hedge Contract*" means any commodity exchange, swap, forward, cap, floor, collar, option or other similar agreement or arrangement entered into for the purpose of reducing the exposure of the Partnership Group to fluctuations in interest rates or the price of hydrocarbons, basis differentials or currency exchange rates in their operations and not for speculative purposes.

"*Holder*" as used in Section 7.13, has the meaning assigned to such term in Section 7.13(a).

"*IDR Reset Common Units*" has the meaning assigned to such term in Section 5.9(a).

"*IDR Reset Election*" has the meaning assigned to such term in Section 5.9(a).

"*Incentive Distribution Right*" means a non-voting Limited Partner Interest issued to the General Partner pursuant to Section 5.2, which Limited Partner Interest will confer upon the holder thereof only the rights and obligations specifically provided in this Agreement with respect to Incentive Distribution Rights (and no other rights otherwise available to or other obligations of a holder of a Partnership Interest). Notwithstanding anything in this Agreement to the contrary, the holder of an Incentive Distribution Right shall not be entitled to vote such Incentive Distribution Right on any Partnership matter except as may otherwise be required by law.

"*Incentive Distributions*" means any amount of cash distributed to the holder(s) of the Incentive Distribution Rights pursuant to Section 6.4(a).

"*including*" means "including, without limitation".

"*Indemnified Persons*" has the meaning assigned to such term in Section 7.13(c).

"*Indemnitee*" means (a) the General Partner, (b) any Departing General Partner, (c) any Person who is or was an Affiliate of the General Partner or any Departing General Partner, (d) any Person who is or was a manager, managing member, officer, director, employee, agent, fiduciary or trustee of any Group Member, the General Partner or any Departing General Partner or any Affiliate of any Group Member, the General Partner or any Departing General Partner, (e) any Person who is or was serving at the request of the General Partner or any Departing General Partner or any Affiliate of the General Partner or any Departing General Partner as a manager, managing member, officer, director, employee, agent, fiduciary or trustee of another Person; *provided* that a Person shall not be an Indemnitee by reason of providing, on a fee-for-services basis, trustee, fiduciary or custodial services; and (f) any Person that the General Partner designates as an "Indemnitee" for purposes of this Agreement.

"*Ineligible Holder*" has the meaning assigned to such term in Section 4.9(c).

"*Initial Common Units*" means the Common Units distributed in the Initial Distribution.

"*Initial Distribution*" means the initial distribution by Atlas Energy, L.P. of Common Units to the unitholders of Atlas Energy, L.P., as described in the Registration Statement.

"*Initial Unit Price*" means with respect to the Common Units, the average of the closing prices of a Common Unit on the NYSE for the five consecutive Trading Days immediately following the date of the Initial Distribution, and for any other class or series of Partnership Interests, the price per Partnership Interest at which such class or series of Partnership Interest is initially sold by the Partnership, as determined by the General Partner, in each case adjusted as the General Partner determines to be appropriate to give effect to any distribution, subdivision or combination of Partnership Interests.

"*Interim Capital Transactions*" means the following transactions if they occur prior to the Liquidation Date: (a) borrowings, refinancings or refundings of indebtedness (other than Working Capital Borrowings and other than for items purchased on open account in the ordinary course of business) by any Group Member and sales of debt securities of any Group Member; (b) issuances of equity interests of any Group Member; and (c) sales or other voluntary or involuntary dispositions of any assets of any Group Member other than (i) sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business and (ii) sales or other dispositions of assets as part of normal retirements or replacements.

"*Investment Capital Expenditures*" means capital expenditures other than Maintenance Capital Expenditures and Expansion Capital Expenditures.

"*Liability*" means any liability or obligation of any nature, whether accrued, contingent or otherwise.

"*Limited Partner*" means, unless the context otherwise requires, the Organizational Limited Partner, the General Partner (with respect to the Incentive Distribution Rights received by it pursuant to Section 5.2 and any Common Units that it may hold), each Additional Limited Partner and any Departing General Partner upon the change of its status from General Partner to Limited Partner pursuant to Section 11.3, in each case, in such Person's capacity as a limited partner of the Partnership; *provided*, *however*, that when the term "Limited Partner" is used herein in the context of any vote or other approval, including Articles XIII and XIV, such term shall not, solely for such purpose, include any holder of an Incentive Distribution Right (solely with respect to its Incentive Distribution Rights and not with respect to any other Limited Partner Interest held by such Person) except as may otherwise be required by law.

"*Limited Partner Interest*" means the ownership interest of a Limited Partner in the Partnership, which may be evidenced by Common Units, Incentive Distribution Rights or other Partnership Interests or a combination thereof or interest therein, and includes any and all benefits to which such Limited Partner is entitled as provided in this Agreement, together with all obligations of such Limited Partner to comply with the terms and provisions of this Agreement; *provided*, *however*, that when the term "Limited Partner Interest" is used herein in the context of any vote or other approval, including Articles XIII and XIV, such term shall not, solely for such purpose, include any holder of an Incentive Distribution Right (solely with respect to its Incentive Distribution Rights and not with respect to any other Limited Partner Interest held by such Person), and that when the term "Limited Partner Interest" is used herein, such term shall not include any holder of a Class A Unit or General Partner Interest (solely with respect to its Class A Units and General Partner Interest), except as may otherwise be required by law.

"*Liquidation Date*" means (a) in the case of an event giving rise to the dissolution of the Partnership of the type described in clauses (a) and (b) of the first sentence of Section 12.2, the date on which the applicable time period during which the holders of Outstanding Units have the right to elect to continue the business of the Partnership has expired without such an election being made, and (b) in the case of any other event giving rise to the dissolution of the Partnership, the date on which such event occurs.

"*Liquidator*" means one or more Persons selected by the General Partner to perform the functions described in Section 12.3 as liquidating trustee of the Partnership within the meaning of the Delaware Act.

"*LTIP*" means the Long-Term Incentive Plan of the General Partner, as it may be amended, or any equity compensation plan successor thereto.

"*Maintenance Capital Expenditures*" means cash expenditures, including expenditures for the addition or improvement to or replacement of the capital assets owned by any Group Member, or for the acquisition of existing, or the construction or development of new, capital assets, including replacement of equipment and oil and natural gas reserves (including non-proved reserves attributable to undeveloped leasehold acreage, properties containing estimated proved reserves and other similar assets), whether through the development, exploitation and production of an existing leasehold or the acquisition or development of a new oil or natural gas property, including to offset expected production declines from producing properties, if such expenditures are made to maintain the levels of oil and natural gas production of the Partnership Group for the long term. Maintenance Capital Expenditures shall not include Expansion Capital Expenditures. Maintenance Capital Expenditures shall include interest (and related fees) on debt incurred and distributions on equity issued, in each case, to finance the construction or development of a replacement asset and paid in respect of the period beginning on the date that a Group Member enters into a binding obligation to commence constructing or developing a replacement asset and ending on the earlier to occur of the date that such replacement asset Commences Commercial Service and the date that such replacement asset is abandoned or disposed of. Debt incurred to pay or equity issued to fund construction or development period interest payments, or such construction or development period distributions on equity, shall also be deemed to be debt or equity, as the case may be, incurred to finance the construction or development of a replacement asset.

"*Merger Agreement*" has the meaning assigned to such term in Section 14.1.

"*Minimum Quarterly Distribution*" means $0.40 per Common Unit per Quarter and $0.40 per Class A Unit per Quarter (or with respect to periods of less than a full fiscal quarter, it means the product of $0.40 multiplied by a fraction, the numerator of which is the number of days in such period and the denominator of which is the total number of days in such fiscal quarter), subject to adjustment in accordance with Sections 5.9, 6.6 and 6.8.

"*National Securities Exchange*" means an exchange registered with the Commission under Section 6(a) of the Securities Exchange Act (or any successor to such Section) and any other securities exchange (whether or not registered with the Commission under Section 6(a) (or successor to such Section) of the Securities Exchange Act) that the General Partner shall designate as a National Securities Exchange for purposes of this Agreement.

"*Net Agreed Value*" means, (a) in the case of any Contributed Property, the Agreed Value of such property reduced by any Liabilities either assumed by the Partnership upon such contribution or to which such property is subject when contributed, and (b) in the case of any property distributed to a Partner by the Partnership, the Partnership's Carrying Value of such property (as adjusted pursuant to Section 5.4(d)(ii)) at the time such property is distributed, reduced by any Liability either assumed by such Partner upon such distribution or to which such property is subject at the time of distribution, in either case, as determined and required by the Treasury Regulations promulgated under Section 704(b) of the Code.

"*Net Income*" means, for any taxable period, the excess, if any, of the Partnership's items of income and gain (other than those items taken into account in the computation of Net Termination Gain or Net Termination Loss) for such taxable period over the Partnership's items of loss and deduction (other than those items taken into account in the computation of Net Termination Gain or Net Termination Loss) for such taxable period. The items included in the calculation of Net Income shall be determined in accordance with Section 5.4(b) and shall include Simulated Gain but shall not include any items specially allocated under Section 6.1(d) or Section 6.1(e); *provided* that the determination of the items that have been specially allocated under Section 6.1(d) shall be made as if Section 6.1(d)(xii) were not in this Agreement.

"*Net Loss*" means, for any taxable period, the excess, if any, of the Partnership's items of loss and deduction (other than those items taken into account in the computation of Net Termination Gain or Net Termination Loss) for such taxable period over the Partnership's items of income and gain (other than those items taken into account in the computation of Net Termination Gain or Net Termination Loss) for such taxable period. The items included in the calculation of Net Loss shall be determined in accordance with Section 5.4(b) and shall include Simulated Gain but shall not include any items specially allocated under Section 6.1(d) or Section 6.1(e); *provided* that the determination of the items that have been specially allocated under Section 6.1(d) shall be made as if Section 6.1(d)(xii) were not in this Agreement.

"*Net Positive Adjustments*" means, with respect to any Partner, the excess, if any, of the total positive adjustments over the total negative adjustments made to the Capital Account of such Partner pursuant to Book-Up Events and Book-Down Events.

"*Net Termination Gain*" means, for any taxable period, the sum, if positive, of all items of income, gain, loss or deduction recognized by the Partnership after the Liquidation Date. The items included in the determination of Net Termination Gain shall be determined in accordance with Section 5.4(b) and shall include Simulated Gain, but shall not include any items of income, gain or loss specially allocated under Section 6.1(d) or Section 6.1(e).

"*Net Termination Loss*" means, for any taxable period, the sum, if negative, of all items of income, gain, loss or deduction recognized by the Partnership after the Liquidation Date. The items included in the determination of Net Termination Loss shall be determined in accordance with Section 5.4(b) and shall include Simulated Gain, but shall not include any items of income, gain or loss specially allocated under Section 6.1(d) or Section 6.1(e).

"*Nonrecourse Built-in Gain*" means with respect to any Contributed Properties or Adjusted Properties that are subject to a mortgage or pledge securing a Nonrecourse Liability, the amount of any taxable gain that would be allocated to the Partners pursuant to Sections 6.2(b)(i)(A), 6.2(b)(ii)(A) and 6.2(b)(iii) if such properties were disposed of in a taxable transaction in full satisfaction of such liabilities and for no other consideration.

"*Nonrecourse Deductions*" means any and all items of loss, deduction or expenditure (including any expenditure described in Section 705(a)(2)(B) of the Code), Simulated Depletion or Simulated Loss that, in accordance with the principles of Treasury Regulation Section 1.704-2(b)(1) and 1.704-2(c), are attributable to a Nonrecourse Liability.

"*Nonrecourse Liability*" has the meaning set forth in Treasury Regulation Section 1.704-2(b)(3).

"*Notice of Election to Purchase*" has the meaning assigned to such term in Section 15.1(b).

"*Operating Expenditures*" means all cash expenditures of the Partnership Group (it being understood that, in calculating the amount of Operating Expenditures in respect of any Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash expenditures by such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100), including taxes, reimbursements of expenses of the General Partner and its Affiliates, payments made in the ordinary course of business under Hedge Contracts, officer compensation, repayment of Working Capital Borrowings, debt service payments and Estimated Maintenance Capital Expenditures, subject to the following:

(a) repayment of Working Capital Borrowings deducted from Operating Surplus pursuant to clause (b)(iii) of the definition of Operating Surplus shall not constitute Operating Expenditures when actually repaid;

(b) payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness other than Working Capital Borrowings shall not constitute Operating Expenditures;

(c) Operating Expenditures shall not include (i) Expansion Capital Expenditures, (ii) actual Maintenance Capital Expenditures, (iii) Investment Capital Expenditures, (iv) payment of transaction expenses (including taxes) relating to Interim Capital Transactions, (v) distributions to Partners (including distributions in respect of any Incentive Distributions Rights) or (vi) repurchases of Partnership Interests, other than repurchases of Partnership Interests to satisfy obligations under employee benefit plans, or reimbursements of expenses of the General Partner for such purchases.

"*Operating Surplus*" means, with respect to any period ending prior to the Liquidation Date, on a cumulative basis and without duplication,

(a) the sum of (i) $60 million, (ii) all cash receipts of the Partnership Group (it being understood that, in calculating the amount of Operating Surplus in respect of any Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash receipts of such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100) for the period beginning on the Closing Date and ending on the last day of such period, including Working Capital Borrowings but excluding cash receipts from Interim Capital Transactions, (iii) all cash receipts of the Partnership Group (it being understood that, in calculating the amount of Operating Surplus in respect of any Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash receipts of such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100) after the end of such period but on or before the date of determination of Operating Surplus with respect to such period resulting from Working Capital Borrowings and (iv) the amount of cash distributions paid on equity issued (including incremental incentive distributions) to finance all or a portion of the construction, acquisition, development or improvement of a Capital Improvement or replacement of a capital asset (such as equipment or reserves) and paid in respect of the period beginning on the date that the Group Member enters into a binding obligation to commence the construction, acquisition, development, replacement or improvement of a Capital Improvement or replacement of a capital asset and ending on the earlier to occur of the date the Capital Improvement or capital asset Commences Commercial Service or the date that it is abandoned or disposed of (equity issued to fund construction period interest payments on debt incurred (including periodic net payments under related interest rate swap agreements), or construction period distributions on equity issued, including incremental incentive distributions, to finance the construction, acquisition, development or improvement of a Capital Improvement or replacement of a capital asset shall also be deemed to be equity issued to finance the construction, acquisition, development, replacement or improvement of a Capital Improvement or replacement of a capital asset for purposes of this clause (iv)); *less*

(b) the sum of (i) Operating Expenditures for the period beginning on the Closing Date and ending on the last day of such period, (ii) the amount of cash reserves established by the General Partner for the Partnership Group (it being understood that, in calculating the amount of Operating Surplus in respect of any Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such cash reserves for such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100) to provide funds for future Operating Expenditures, (iii) all Working Capital Borrowings not repaid within twelve months after having been incurred or repaid within such 12-month period with the proceeds of additional Working Capital Borrowings and (iv) any cash loss realized on the disposition of an Investment Capital Expenditure;

provided, *however*, that disbursements made (including contributions to a Group Member or disbursements on behalf of a Group Member) or cash reserves established, increased or reduced after the end of such period but on or before the date of determination of Available Cash with respect to such period shall be deemed to have been made, established, increased or reduced, for purposes of determining Operating Surplus, within such period if the General Partner so determines.

Notwithstanding the foregoing, "Operating Surplus" with respect to the Quarter in which the Liquidation Date occurs and any subsequent Quarter shall equal zero.

"*Opinion of Counsel*" means a written opinion of counsel (who may be regular counsel to the Partnership or the General Partner or any of its Affiliates) acceptable to the General Partner.

"*Organizational Limited Partner*" means Atlas Energy, L.P. in its capacity as the organizational limited partner of the Partnership pursuant to this Agreement.

"*Outstanding*" means, with respect to Partnership Interests, all Partnership Interests that are issued by the Partnership and reflected as outstanding on the Partnership's books and records as of the date of determination; *provided*, *however*, that if at any time any Person or Group (other than the General Partner or its Affiliates) beneficially owns 20% or more of the Outstanding Units of any class, all Units owned by such Person or Group shall not be voted (and shall not be entitled to be voted) on any matter and shall not be considered to be Outstanding when sending notices of a meeting of Limited Partners to vote on any matter (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under this Agreement, except that Units so owned shall be considered to be Outstanding for purposes of Section 11.1(b)(iv) (such Units shall not, however, be treated as a separate class of Partnership Interests for purposes of this Agreement or the Delaware Act); *provided*, *further*, that the foregoing limitation shall not apply to (i) any Person or Group who acquired 20% or more of the Outstanding Units of any class directly from the General Partner or its Affiliates (other than the Partnership), (ii) any Person or Group who acquired 20% or more of the Outstanding Units of any class directly or indirectly from a Person or Group described in clause (i), *provided* that, upon or prior to such acquisition, the General Partner shall have notified such Person or Group in writing that such limitation shall not apply or (iii) any Person or Group who acquired 20% or more of the Outstanding Units directly from the Partnership if the General Partner shall have notified such Person or Group in writing that such limitation shall not apply.

"*Partner Nonrecourse Debt*" has the meaning set forth in Treasury Regulation Section 1.704-2(b)(4).

"*Partner Nonrecourse Debt Minimum Gain*" has the meaning set forth in Treasury Regulation Section 1.704-2(i)(2).

"*Partner Nonrecourse Deductions*" means any and all items of loss, deduction or expenditure (including any expenditure described in Section 705(a)(2)(B) of the Code), Simulated Depletion or Simulated Loss that, in accordance with the principles of Treasury Regulation Section 1.704-2(i)(1) and 1.704-2(i)(2), are attributable to a Partner Nonrecourse Debt.

"*Partners*" means the General Partner and the Limited Partners.

"*Partnership*" means Atlas Resource Partners, L.P., a Delaware limited partnership, and any successors thereto.

"*Partnership Group*" means the Partnership and its Subsidiaries, treated as a single consolidated entity.

"*Partnership Interest*" means any equity interest in the Partnership, which shall include any General Partner Interest and Limited Partner Interests but shall exclude options, warrants, rights and appreciation rights relating to an equity interest in the Partnership.

"*Partnership Minimum Gain*" means that amount determined in accordance with the principles of Treasury Regulation Section 1.704-2(b)(2) and 1.704-2(d).

"*Per Unit Capital Amount*" means, as of any date of determination, the Capital Account, stated on a per Unit basis, underlying any Partnership Interest held by a Person other than the General Partner or any Affiliate of the General Partner who holds Partnership Interests.

"*Percentage Interest*" means as of any date of determination, (a) as to any holder of Class A Units, the Percentage Interest attributable to such Class A Units shall equal the product obtained by multiplying (i) 100% less the percentage applicable to clause (c) below by (ii) the quotient obtained by dividing (x) the number of Class A Units held by such holder by (y) the sum of the total number of all Outstanding Common Units and the total number of Outstanding Class A Units; (b) as to any holder of Common Units, the Percentage Interest attributable to such Common Units shall equal the product obtained by multiplying (i) 100% less the percentage applicable to clause (c) below by (ii) the quotient obtained by dividing (x) the number of Common Units held by such holder by (y) the sum of the total number of all Outstanding Common Units and the total number of Outstanding Class A Units; and (c) as to the holders of additional Partnership Interests issued by the Partnership in accordance with Section 5.5, the percentage established as a part of such issuance. Unless the context otherwise requires, references to the Percentage Interest of any holder of more than one class or series of Partnership Interests shall mean the aggregate Percentage Interest attributable to all such Partnership Interests. The Percentage Interest with respect to an Incentive Distribution Right shall at all times be zero.

"*Person*" means an individual or a corporation, firm, limited liability company, partnership, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof or other entity.

"*Plan of Conversion*" has the meaning assigned to such term in Section 14.1.

"*Pro Rata*" means (a) when used with respect to Partnership Interests or any class or classes thereof, apportioned equally among all designated Partnership Interests in accordance with their relative Percentage Interests, (b) when used with respect to Partners or Record Holders, apportioned among all Partners or Record Holders in accordance with their relative Percentage Interests and (c) when used with respect to holders of Incentive Distribution Rights, apportioned equally among all holders of Incentive Distribution Rights in accordance with the relative number or percentage of Incentive Distribution Rights held by each such holder.

"*Purchase Date*" means the date determined by the General Partner as the date for purchase of all Outstanding Limited Partner Interests of a certain class (other than Limited Partner Interests owned by the General Partner and its Affiliates) pursuant to Article XV.

"*Quarter*" means, unless the context requires otherwise, a fiscal quarter of the Partnership, or, with respect to the fiscal quarter of the Partnership that includes the Closing Date, the portion of such fiscal quarter after the Closing Date.

"*Rate Eligibility Trigger*" has the meaning assigned to such term in Section 4.9(a)(i).

"*Recapture Income*" means any gain recognized by the Partnership (computed without regard to any adjustment required by Section 734 or Section 743 of the Code) upon the disposition of any property or asset of the Partnership, which gain is characterized as ordinary income because it represents the recapture of deductions previously taken with respect to such property or asset.

"*Record Date*" means the date established by the General Partner or otherwise in accordance with this Agreement for determining (a) the identity of the Record Holders entitled to notice of, or to vote at, any meeting of Limited Partners or entitled to vote by ballot or give approval of Partnership action in writing without a meeting or entitled to exercise rights in respect of any lawful action of Limited Partners or (b) the identity of Record Holders entitled to receive any report or distribution or to participate in any offer.

"*Record Holder*" means (a) with respect to Partnership Interests of any class for which a Transfer Agent has been appointed, the Person in whose name a Partnership Interest of such class is registered on the books of the Transfer Agent as of the opening of business on a particular Business Day or (b) with respect to other classes of Partnership Interests, the Person in whose name any such other Partnership Interest is registered on the books that the General Partner has caused to be kept as of the opening of business on such Business Day.

"*Redeemable Interests*" means any Partnership Interests for which a redemption notice has been given, and has not been withdrawn, pursuant to Section 4.10.

"*Registration Statement*" means the Registration Statement on Form 10 (File No. 001-35317), as it has been or as it may be amended or supplemented from time to time, filed by the Partnership with the Commission to register the Common Units under the Exchange Act.

"*Remaining Net Positive Adjustments*" means as of the end of any taxable period, (i) with respect to the Unitholders, the excess of (a) the Net Positive Adjustments of the Unitholders as of the end of such period over (b) the sum of those Partners' Share of Additional Book Basis Derivative Items for each prior taxable period, (ii) with respect to the General Partner (as holder of the Class A Units), the excess of (a) the Net Positive Adjustments of the General Partner as of the end of such period over (b) the sum of the General Partner's Share of Additional Book Basis Derivative Items with respect to the Class A Units for each prior taxable period, and (iii) with respect to the holders of Incentive Distribution Rights, the excess of (a) the Net Positive Adjustments of the holders of Incentive Distribution Rights as of the end of such period over (b) the sum of the Share of Additional Book Basis Derivative Items of the holders of the Incentive Distribution Rights for each prior taxable period.

"*Required Allocations*" means any allocation of an item of income, gain, loss, deduction, Simulated Depletion or Simulated Loss pursuant to Section 6.1(d)(i), 6.1(d)(ii), 6.1(d)(iv), 6.1(d)(v), 6.1(d)(vi), 6.1(d)(vii), 6.1(d)(viii), 6.1(d)(ix) or 6.1(e).

"*Reset MQD*" has the meaning assigned to such term in Section 5.9(a).

"*Reset Notice*" has the meaning assigned to such term in Section 5.9(b).

"*Residual Gain*" or "*Residual Loss*" means any item of gain or loss, or Simulated Gain or Simulated Loss, as the case may be, of the Partnership recognized for U.S. federal income tax purposes resulting from a sale, exchange or other disposition of a Contributed Property or Adjusted Property, to the extent such item of gain or loss or Simulated Gain or Simulated Loss is not allocated pursuant to Section 6.2(b)(i)(A) or 6.2(b)(ii)(A), respectively, to eliminate Book-Tax Disparities.

"*Second Liquidation Target Amount*" has the meaning assigned to such term in Section 6.1(c)(i)(D).

"*Second Target Distribution*" means $0.50 per Common Unit per Quarter and $0.50 per Class A Unit per Quarter (or, with respect to periods of less than a full fiscal quarter, it means the product of $0.50 multiplied by a fraction of which the numerator is equal to the number of days in such period and of which the denominator is the total number of days in such fiscal quarter), subject to adjustment in accordance with Sections 5.9, 6.6 and 6.8.

"*Securities Act*" means the U.S. Securities Act of 1933, as amended, supplemented or restated from time to time and any successor to such statute.

"*Securities Exchange Act*" means the Securities Exchange Act of 1934, as amended, supplemented or restated from time to time and any successor to such statute.

"*Separation Agreement*" means that certain Separation and Distribution Agreement, dated as of [●], 2012, by and among the General Partner, the Partnership and the Organizational Limited Partner.

"*Share of Additional Book Basis Derivative Items*" means in connection with any allocation of Additional Book Basis Derivative Items for any taxable period, (i) with respect to the Unitholders, the amount that bears the same ratio to such Additional Book Basis Derivative Items as the Unitholders' Remaining Net Positive Adjustments as of the end of such taxable period bears to the Aggregate Remaining Net Positive Adjustments as of that time, (ii) with respect to the General Partner (as holder of the Class A Units), the amount that bears the same ratio to such Additional Book Basis Derivative Items as the General Partner's Remaining Net Positive Adjustments as of the end of such taxable period bears to the Aggregate Remaining Net Positive Adjustment as of that time, and (iii) with respect to the Partners holding Incentive Distribution Rights, the amount that bears the same ratio to such Additional Book Basis Derivative Items as the Remaining Net Positive Adjustments of the Partners holding the Incentive Distribution Rights as of the end of such taxable period bears to the Aggregate Remaining Net Positive Adjustments as of that time.

"*Simulated Basis*" means the Carrying Value of any oil and gas property (as defined in Section 614 of the Code).

"*Simulated Depletion*" means, with respect to an oil and gas property (as defined in Section 614 of the Code), a depletion allowance computed in accordance with U.S. federal income tax principles (as if the Simulated Basis of the property was its adjusted tax basis) and in the manner specified in Treasury Regulation Section 1.704-1(b)(2)(iv)(k)(2). For purposes of computing Simulated Depletion with respect to any property, the Simulated Basis of such property shall be deemed to be the Carrying Value of such property, and in no event shall such allowance for Simulated Depletion, in the aggregate, exceed such Simulated Basis.

"*Simulated Gain*" means the excess, if any, of the amount realized from the sale or other disposition of an oil or gas property over the Carrying Value of such property.

"*Simulated Loss*" means the excess, if any, of the Carrying Value of an oil or gas property over the amount realized from the sale or other disposition of such property.

"*Special Approval*" means approval by a majority of the members of the Conflicts Committee.

"*Subsidiary*" means, with respect to any Person, (a) a corporation of which more than 50% of the voting power of shares entitled (without regard to the occurrence of any contingency) to vote in the election of directors or other governing body of such corporation is owned, directly or indirectly, at the date of determination, by such Person, by one or more Subsidiaries of such Person or a combination thereof, (b) a partnership (whether general or limited in which such Person or a Subsidiary of such Person is, at the date of determination, a general or limited partner of such partnership, but only if more than 50% of the partnership interests of such partnership (considering all of the partnership interests of the partnership as a single class) is owned, directly or indirectly, at the date of determination, by such Person, by one or more Subsidiaries of such Person, or a combination thereof, or (c) any other Person (other than a corporation or partnership) in which such Person, one or more Subsidiaries of such Person, or a combination thereof, directly or indirectly, at the date of determination, has (i) at least a majority ownership interest or (ii) the power to elect or direct the election of a majority of the directors or other governing body of such Person.

"*Surviving Business Entity*" has the meaning assigned to such term in Section 14.2(b).

"*Target Distributions*" means, collectively, the First Target Distribution, the Second Target Distribution and the Third Target Distribution.

"*Third Target Distribution*" means $0.60 per Common Unit per Quarter and $0.60 per Class A Unit per Quarter (or, with respect to periods of less than a full fiscal quarter, it means the product of $0.60 multiplied by a fraction of which the numerator is equal to the number of days in such period and of which the denominator is the total number of days in such fiscal quarter), subject to adjustment in accordance with Sections 5.9, 6.6 and 6.8.

"*Trading Day*" has the meaning assigned to such term in Section 15.1(a).

"*transfer*" has the meaning assigned to such term in Section 4.4(a).

"*Transfer Agent*" means such bank, trust company or other Person (including the General Partner or one of its Affiliates) as shall be appointed from time to time by the General Partner or the Partnership to act as registrar and transfer agent for any class of Partnership Interests; *provided* that if no Transfer Agent is specifically designated for any class of Partnership Interests, the General Partner shall act in such capacity.

"*Unit*" means a Partnership Interest that is designated as a "Unit" and shall include Common Units but shall not include (a) Class A Units (or the General Partner Interest represented thereby) or (b) Incentive Distribution Rights.

"*Unit Majority*" means at least a majority of the Outstanding Common Units, including Common Units held by the General Partner and its Affiliates.

"*Unitholders*" means the holders of Partnership Interests.

"*Unpaid MQD*" has the meaning assigned to such term in Section 6.1(c)(i)(B).

"*Unrealized Gain*" attributable to any item of Partnership property means, as of any date of determination, the excess, if any, of (a) the fair market value of such property as of such date (as determined under Section 5.4(d)) over (b) the Carrying Value of such property as of such date (prior to any adjustment to be made pursuant to Section 5.4(d) as of such date).

"*Unrealized Loss*" attributable to any item of Partnership property means, as of any date of determination, the excess, if any, of (a) the Carrying Value of such property as of such date (prior to any adjustment to be made pursuant to Section 5.4(d) as of such date) over (b) the fair market value of such property as of such date (as determined under Section 5.4(d)).

"*Unrecovered Capital*" means at any time, with respect to a Unit, the Initial Unit Price less the sum of all distributions constituting Capital Surplus theretofore made in respect of an Initial Common Unit and any distributions of cash (or the Net Agreed Value of any distributions in kind) in connection with the dissolution and liquidation of the Partnership theretofore made in respect of an Initial Common Unit, adjusted as the General Partner determines to be appropriate to give effect to any distribution, subdivision or combination of such Units.

"*Unrestricted Person*" means (a) each Indemnitee, (b) each Partner, (c) each Person who is or was a member, partner, director, officer, employee or agent of any Group Member, a General Partner or any Departing General Partner or any Affiliate of any Group Member, a General Partner or any Departing General Partner and (d) any Person the General Partner designates as an "Unrestricted Person" for purposes of this Agreement.

"*U.S. GAAP*" means United States generally accepted accounting principles, as in effect from time to time, consistently applied.

"*Withdrawal Opinion of Counsel*" has the meaning assigned to such term in Section 11.1(b).

"*Working Capital Borrowings*" means borrowings of the Partnership Group (it being understood that, in calculating the amount of Working Capital Borrowings in respect of any Subsidiary of the Partnership that is not directly or indirectly wholly owned by the Partnership, such borrowings by such Subsidiary shall be multiplied by a fraction, the numerator of which is the percentage of equity in such Subsidiary held directly or indirectly by the Partnership and the denominator of which is 100) made pursuant to a credit facility, commercial paper facility or other similar financing arrangement that are used solely for working capital purposes or to pay distributions to the Partners; *provided* that when such borrowings are incurred it is the intent of the borrower to repay such borrowings within 12 months from the date of such borrowings from sources other than additional Working Capital Borrowings.

SECTION 1.2. *Construction*.

Unless the context requires otherwise: (a) any pronoun used in this Agreement shall include the corresponding masculine, feminine or neuter forms, and the singular form of nouns, pronouns and verbs shall include the plural and vice versa; (b) references to Articles and Sections refer to Articles and Sections of this Agreement; (c) the terms "include," "includes" or "including" or words of like import shall be deemed to be followed by the words "without limitation;" and (d) the terms "hereof," "herein" or "hereunder" refer to this Agreement as a whole and not to any particular provision of this Agreement. The table of contents and headings contained in this Agreement are for reference purposes only and shall not affect in any way the meaning or interpretation of this Agreement.

ARTICLE II

ORGANIZATION

SECTION 2.1. *Formation*.

The Partnership was formed on October 13, 2011 pursuant to the Certificate of Limited Partnership as filed with the Secretary of State of the State of Delaware pursuant to the provisions of the Delaware Act. The General Partner and the Organizational Limited Partner hereby amend and restate the original Agreement of Limited Partnership of Atlas Resource Partners, L.P. in its entirety in the form of this Agreement, and this amendment and restatement shall become effective on the date hereof. Except as expressly provided to the contrary in this Agreement, the rights, duties (including fiduciary duties), liabilities and obligations of the Partners and the administration, dissolution and termination of the Partnership shall be governed by the Delaware Act. All Partnership Interests shall constitute personal property of the owner thereof for all purposes.

SECTION 2.2. *Name*.

The name of the Partnership shall be "Atlas Resource Partners, L.P." The Partnership's business may be conducted under any other name or names as determined by the General Partner, including the name of the General Partner. The words "Limited Partnership," "L.P.," "Ltd." or similar words or letters shall be included in the Partnership's name where necessary for the purpose of complying with the laws of any jurisdiction that so requires. The General Partner may change the name of the Partnership at any time and from time to time and shall notify the Limited Partners of such change in the next regular communication to the Limited Partners.

SECTION 2.3. *Registered Office; Registered Agent; Principal Office; Other Offices*.

Unless and until changed by the General Partner, the registered office of the Partnership in the State of Delaware shall be located at 2711 Centerville Road, Suite 400, Wilmington, Delaware 19808, and the registered agent for service of process on the Partnership in the State of Delaware at such registered office shall be The Corporation Service Company. The principal office of the Partnership shall be located at Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275 or such other place as the General Partner may from time to time designate by notice to the Limited Partners (which notice may be satisfied by indicating such other place in a public filing with the Commission). The Partnership may maintain offices at such other place or places within or outside the State of Delaware as the General Partner determines to be necessary or appropriate. The address of the General Partner shall be Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275 or such other place as the General Partner may from time to time designate by notice to the Limited Partners (which notice may be satisfied by indicating such other place in a public filing with the Commission).

SECTION 2.4. *Purpose and Business*.

The purpose and nature of the business to be conducted by the Partnership shall be to (a) engage directly in, or enter into or form, hold and dispose of any corporation, partnership, joint venture, limited liability company or other arrangement to engage indirectly in, any business activity that is approved by the General Partner, in its sole discretion, and that lawfully may be conducted by a limited partnership organized pursuant to the Delaware Act and, in connection therewith, to exercise all of the rights and powers conferred upon the Partnership pursuant to the agreements relating to such business activity; and (b) do anything necessary or appropriate to the foregoing, including the making of capital contributions or loans to a Group Member; *provided*, *however*, that the General Partner shall not cause the Partnership to engage, directly or indirectly, in any business activity that the General Partner determines would cause the Partnership to be treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes. To the fullest extent permitted by law, the General Partner shall have no duty or obligation to propose or approve, and may, in its sole discretion, decline to propose or approve, the conduct by the Partnership of any business, free of any duty or obligation whatsoever to the Partnership or any Limited Partner and, in declining to so propose or approve, shall not be required to act in good faith or pursuant to any other standard imposed by this Agreement, any other agreement contemplated hereby or under the Delaware Act or any other law, rule or regulation or at equity.

SECTION 2.5. *Powers*.

The Partnership shall be empowered to do any and all acts and things necessary, appropriate, proper, advisable, incidental to or convenient for the furtherance and accomplishment of the purposes and business described in Section 2.4 and for the protection and benefit of the Partnership.

SECTION 2.6. *Term*.

The term of the Partnership commenced upon the filing of the Certificate of Limited Partnership in accordance with the Delaware Act and shall continue in existence until the dissolution of the Partnership in accordance with the provisions of Article XII. The existence of the Partnership as a separate legal entity shall continue until the cancellation of the Certificate of Limited Partnership as provided in the Delaware Act.

SECTION 2.7. *Title to Partnership Assets*.

Title to Partnership assets, whether real, personal or mixed and whether tangible or intangible, shall be deemed to be owned by the Partnership as an entity, and no Partner, individually or collectively, shall have any ownership interest in such Partnership assets or any portion thereof. Title to any or all of the Partnership assets may be held in the name of the Partnership, the General Partner, one or more of its Affiliates or one or more nominees, as the General Partner may determine. The General Partner hereby declares and warrants that any Partnership assets for which record title is held in the name of the General Partner or one or more of its Affiliates or one or more nominees shall be held by the General Partner or such Affiliate or nominee for the use and benefit of the Partnership in accordance with the provisions of this Agreement; *provided*, *however*, that the General Partner shall use reasonable efforts to cause record title to such assets (other than those assets in respect of which the General Partner determines that the expense and difficulty of conveyancing makes transfer of record title to the Partnership impracticable) to be vested in the Partnership or one or more of the Partnership's designated Affiliates as soon as reasonably practicable; *provided*, *further*, that, prior to the withdrawal or removal of the General Partner or as soon thereafter as practicable, the General Partner shall use reasonable efforts to effect the transfer of record title to the Partnership and, prior to any such transfer, will provide for the use of such assets in a manner satisfactory to the General Partner. All Partnership assets shall be recorded as the property of the Partnership in its books and records, irrespective of the name in which record title to such Partnership assets is held.

ARTICLE III

RIGHTS OF LIMITED PARTNERS

SECTION 3.1. *Limitation of Liability*.

The Limited Partners shall have no liability under this Agreement except as expressly required under this Agreement or the Delaware Act.

SECTION 3.2. *Management of Business*.

No Limited Partner, in its capacity as such, shall participate in the operation, management or control (within the meaning of the Delaware Act) of the Partnership's business, transact any business in the Partnership's name or have the power to sign documents for or otherwise bind the Partnership. Any action taken by any

Affiliate of the General Partner or any officer, director, employee, manager, member, general partner, agent or trustee of the General Partner or any of its Affiliates, or any officer, director, employee, manager, member, general partner, agent or trustee of a Group Member, in its capacity as such, shall not be deemed to be participating in the control of the business of the Partnership by a limited partner of the Partnership (within the meaning of Section 17-303(a) of the Delaware Act) and shall not affect, impair or eliminate the limitations on the liability of the Limited Partners under this Agreement.

SECTION 3.3. *Outside Activities of Limited Partners*.

Any Limited Partner shall be entitled to and may have business interests and engage in business activities in addition to those relating to the Partnership, including business interests and activities in direct competition with the Partnership Group. Neither the Partnership nor any of the other Partners shall have any rights by virtue of this Agreement in any business ventures of any Limited Partner.

SECTION 3.4. *Rights of Limited Partners*.

(a) In addition to other rights provided by this Agreement or by applicable law (other than Section 17-305 of the Delaware Act, which is restricted to the extent set forth below), and except as limited by Section 3.4(b), each Limited Partner shall have the right, for a purpose reasonably related, as determined by the General Partner, to such Limited Partner's interest as a Limited Partner in the Partnership, upon reasonable written demand stating the purpose of such demand and at such Limited Partner's own expense:

(i) to obtain true and full information regarding the status of the business and financial condition of the Partnership; *provided*, *however*, that the requirements of this Section 3.4(a)(i) shall be satisfied by furnishing to a Limited Partner upon its demand pursuant to this Section 3.4(a)(i) either (A) the Partnership's most recent filings with the Commission on Form 10-K and any subsequent filings on Form 10-Q and 8-K or (B) if the Partnership is no longer subject to the reporting requirements of the Exchange Act, the information specified in, and meeting the requirements of, Rule 144A(d)(4) under the Securities Act;

(ii) promptly after its becoming available, to obtain a copy of the Partnership's federal, state and local income tax returns for each year;

(iii) to obtain a current list of the name and last known business, residence or mailing address of each Partner;

(iv) to obtain a copy of this Agreement and the Certificate of Limited Partnership and all amendments thereto, together with a copy of the executed copies of all powers of attorney pursuant to which this Agreement, the Certificate of Limited Partnership and all amendments thereto have been executed;

(v) to obtain true and full information regarding the amount of cash and a description and statement of the Net Agreed Value of any other Capital Contribution by each Partner and that each Partner has agreed to contribute in the future, and the date on which each became a Partner; and

(vi) to obtain such other information regarding the affairs of the Partnership as is just and reasonable.

(b) Notwithstanding any other provision of this Agreement, the General Partner may keep confidential from the Limited Partners, for such period of time as the General Partner determines, (i) any information that the General Partner reasonably believes to be in the nature of trade secrets or (ii) other information the disclosure of which the General Partner believes (A) is not in the best interests of the Partnership or the Partnership Group, (B) could damage the Partnership or the Partnership Group or its business or (C) that any Group Member is required by law or by agreement with any third party to keep confidential (other than agreements with Affiliates of the Partnership the primary purpose of which is to circumvent the obligations set forth in this Section 3.4).

ARTICLE IV

CERTIFICATES; RECORD HOLDERS;
TRANSFER OF PARTNERSHIP INTERESTS;
REDEMPTION OF PARTNERSHIP INTERESTS

SECTION 4.1. *Certificates*.

Notwithstanding anything to the contrary in this Agreement, unless the General Partner shall determine otherwise in respect of some or all of any or all classes of Partnership Interests, Partnership Interests shall not be evidenced by physical certificates. Certificates that may be issued, if any, shall be executed on behalf of the Partnership by the Chairman of the Board, Chief Executive Officer, President, Chief Financial Officer or any Executive Vice President or Vice President and the Secretary, any Assistant Secretary or other authorized officer or director of the General Partner. If a Transfer Agent has been appointed for a class of Partnership Interests, no Certificate, if any, for such class of Partnership Interests shall be valid for any purpose until it has been countersigned by the Transfer Agent for such class of Partnership Interests; *provided*, *however*, that if the General Partner elects to cause the Partnership to issue Partnership Interests of such class in global form, the Certificate, if any, shall be valid upon receipt of a certificate from the Transfer Agent certifying that the Partnership Interests have been duly registered in accordance with the directions of the Partnership.

SECTION 4.2. *Mutilated, Destroyed, Lost or Stolen Certificates*.

(a) To the extent any Partnership Interest is represented by a Certificate, if any mutilated Certificate is surrendered to the Transfer Agent, the appropriate officers of the General Partner on behalf of the Partnership shall execute, and the Transfer Agent shall countersign and deliver in exchange therefor, a new Certificate evidencing the same number and type of Partnership Interests as the Certificate so surrendered.

(b) The appropriate officers of the General Partner on behalf of the Partnership shall execute and deliver, and the Transfer Agent shall countersign a new Certificate in place of any Certificate previously issued if the Record Holder of the Certificate:

(i) makes proof by affidavit, in form and substance satisfactory to the General Partner, that a previously issued Certificate has been lost, destroyed or stolen;

(ii) requests the issuance of a new Certificate before the General Partner has notice that the Certificate has been acquired by a purchaser for value in good faith and without notice of an adverse claim;

(iii) if requested by the General Partner, delivers to the General Partner a bond, in form and substance satisfactory to the General Partner, with surety or sureties and with fixed or open penalty as the General Partner may direct, to indemnify the Partnership, the Partners, the General Partner and the Transfer Agent against any claim that may be made on account of the alleged loss, destruction or theft of the Certificate; and

(iv) satisfies any other reasonable requirements imposed by the General Partner.

(c) If a Limited Partner fails to notify the General Partner within a reasonable period of time after such Limited Partner has notice of the loss, destruction or theft of a Certificate, and a transfer of the Limited Partner Interests represented by the Certificate is registered before the Partnership, the General Partner or the Transfer Agent receives such notification, to the fullest extent permitted by law, the Limited Partner shall be precluded from making any claim against the Partnership, the General Partner or the Transfer Agent for such transfer or for a new Certificate.

(d) As a condition to the issuance of any new Certificate under this Section 4.2, the General Partner may require the payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto and any other expenses (including the fees and expenses of the Transfer Agent) reasonably connected therewith.

SECTION 4.3. *Record Holders*.

The Partnership shall be entitled to recognize the Record Holder as the Partner with respect to any Partnership Interest and, accordingly, shall not be bound to recognize any equitable or other claim to, or interest in, such Partnership Interest on the part of any other Person, regardless of whether the Partnership shall have actual or other notice thereof, except as otherwise provided by law or any applicable rule, regulation, guideline or requirement of any National Securities Exchange on which such Partnership Interests are listed or admitted for trading. Without limiting the foregoing, when a Person (such as a broker, dealer, bank, trust company or clearing corporation or an agent of any of the foregoing) is acting as nominee, agent or in some other representative capacity for another Person in acquiring and/or holding Partnership Interests, as between the Partnership on the one hand, and such other Persons on the other, such representative Person shall be (a) the Record Holder of such Partnership Interest and (b) bound by this Agreement and shall have the rights and obligations of a Partner hereunder as, and to the extent, provided herein.

SECTION 4.4. *Transfer Generally*.

(a) The term "*transfer*," when used in this Agreement with respect to a Partnership Interest, shall be deemed to refer to a transaction (i) by which the General Partner assigns its Class A Units to another Person, and includes a sale, assignment, gift, pledge, encumbrance, hypothecation, mortgage, exchange or any other disposition or (ii) by which the holder of a Limited Partner Interest (including any Incentive Distribution Rights) assigns such Limited Partner Interest to another Person who is or becomes a Limited Partner, and includes a sale, assignment, gift, exchange or any other disposition, in each of cases (i) and (ii), excluding a pledge, encumbrance, hypothecation or mortgage but including any transfer upon foreclosure of any pledge, encumbrance, hypothecation or mortgage.

(b) No Partnership Interest shall be transferred, in whole or in part, except in accordance with the terms and conditions set forth in this Article IV. Any transfer or purported transfer of a Partnership Interest not made in accordance with this Article IV shall be null and void.

(c) Nothing contained in this Agreement shall be construed to prevent any sale, assignment, gift, exchange or any other disposition by any stockholder, member, partner or other owner of the General Partner or any Affiliate of the General Partner of any or all of the equity interests or other ownership interests in the General Partner or such Affiliate, including through a merger or consolidation of the General Partner or any such Affiliate, and the term "transfer" shall not mean any such sale, assignment, gift, exchange or any other disposition.

SECTION 4.5. *Registration and Transfer of Limited Partner Interests*.

(a) The General Partner shall keep or cause to be kept on behalf of the Partnership a register in which, subject to such reasonable regulations as it may prescribe and subject to the provisions of Section 4.5(b), the Partnership will provide for the registration and transfer of Limited Partner Interests. The Partnership shall not recognize transfers of Certificates evidencing Limited Partner Interests unless such transfers are effected in the manner described in this Section 4.5.

(b) The General Partner shall not recognize any transfer of Limited Partner Interests evidenced by Certificates until the Certificates evidencing such Limited Partner Interests are surrendered for registration of transfer. No charge shall be imposed by the General Partner for such transfer; *provided* that, as a condition to the issuance of any new Certificate under this Section 4.5, the General Partner may require the payment of a sum sufficient to cover any tax or other governmental charge that may be imposed with respect thereto. Upon surrender of a Certificate for registration of transfer of any Limited Partner Interests evidenced by a Certificate, and subject to the provisions of this Section 4.5(b), the appropriate officers of the General Partner on behalf of the Partnership shall execute and deliver, and in the case of Certificates evidencing Limited Partner Interests for which a Transfer Agent has been appointed, the Transfer Agent shall countersign and deliver, in the name of the holder or the designated transferee or transferees, as required pursuant to the holder's instructions, one or more new Certificates evidencing the same aggregate number and type of Limited Partner Interests as was evidenced by the Certificate so surrendered.

(c) Upon the receipt of proper transfer instructions from the registered owner of uncertificated Limited Partner Interests, such uncertificated Limited Partner Interests shall be cancelled, issuance of new equivalent uncertificated Limited Partner Interests or Certificates shall be made to the holder of the Limited Partner Interests entitled thereto and the transaction shall be recorded upon the Partnership's register.

(d) By acceptance of the transfer of any Limited Partner Interests in accordance with this Section 4.5, and except as provided in Section 4.9, each transferee of a Limited Partner Interest (including any nominee holder or an agent or representative acquiring such Limited Partner Interests for the account of another Person) (i) shall be admitted to the Partnership as a Limited Partner with respect to the Limited Partner Interests so transferred to such Person when any such transfer or admission is reflected in the books and records of the Partnership and such Limited Partner becomes the Record Holder of the Limited Partner Interests so transferred, (ii) shall become bound, and shall be deemed to have agreed to be bound, by the terms of this Agreement, (iii) represents that the transferee has the capacity, power and authority to enter into this Agreement, and (iv) makes the consents, acknowledgements and waivers contained in this Agreement, all with or without execution of this Agreement by such Person. The transfer of any Limited Partner Interests and the admission of any new Limited Partner shall not constitute an amendment to this Agreement.

(e) Subject to (i) the foregoing provisions of this Section 4.5, (ii) Section 4.3, (iii)Section 4.8, (iv) with respect to any class or series of Limited Partner Interests, the provisions of any statement of designations or amendment to this Agreement establishing such class or series, (v) any contractual provisions binding on any Limited Partner and (vi) provisions of applicable law including the Securities Act, Limited Partner Interests shall be freely transferable.

(f) The General Partner and its Affiliates shall have the right at any time to transfer any or all of their Common Units to one or more Persons without Unitholder approval.

SECTION 4.6. *Transfer of the General Partner Interest*.

(a) Subject to Section 4.6(c), prior to the tenth anniversary of the date of the Initial Distribution, the General Partner shall not transfer all or any part of its General Partner Interest (represented by Class A Units) to a Person unless such transfer (i) has been approved by the prior written consent or vote of the holders of at least a majority of the Outstanding Common Units (excluding Common Units held by the General Partner and its Affiliates) or (ii) is of all, but not less than all, of its General Partner Interest to (A) an Affiliate of the General Partner (other than an individual) or (B) another Person (other than an individual) in connection with the merger or consolidation of the General Partner with or into another Person or the transfer by the General Partner of all or substantially all of its assets to another Person.

(b) Subject to Section 4.6(c), on or after the tenth anniversary of the date of the Initial Distribution, the General Partner may transfer all or any part of its General Partner Interest (represented by Class A Units) to any Person without Unitholder approval.

(c) Notwithstanding anything herein to the contrary, no transfer by the General Partner of all or any part of its General Partner Interest (represented by Class A Units) to another Person shall be permitted unless (i) the transferee agrees to assume the rights and duties of the General Partner under this Agreement and to be bound by the provisions of this Agreement, (ii) the Partnership receives an Opinion of Counsel that such transfer would not result in the loss of limited liability of any Limited Partner under the Delaware Act or cause the Partnership to be treated as an association taxable as a corporation or otherwise to be taxed as an entity for U.S. federal income tax purposes (to the extent not already so treated or taxed) and (iii) such transferee also agrees to purchase all (or the appropriate portion thereof, if applicable) of the partnership or membership interest of the General Partner as the general partner or managing member, if any, of each other Group Member. In the case of a transfer pursuant to and in compliance with this Section 4.6, the transferee or successor (as the case may be) shall, subject to compliance with the terms of Section 10.2, be admitted to the Partnership as the General Partner effective immediately prior to the transfer of the General Partner Interest, and the business of the Partnership shall continue without dissolution.

SECTION 4.7. *Transfer of Incentive Distribution Rights*.

The General Partner or any other holder of Incentive Distribution Rights may transfer any or all of its Incentive Distribution Rights to any Person without Unitholder approval.

SECTION 4.8. *Restrictions on Transfers*.

(a) Except as provided in Section 4.8(c), notwithstanding the other provisions of this Article IV, no transfer of any Partnership Interests shall be made if such transfer would (i) violate the then-applicable federal or state securities laws or rules and regulations of the Commission, any state securities commission or any other governmental authority with jurisdiction over such transfer, (ii) terminate the existence or qualification of the Partnership under the laws of the jurisdiction of its formation or (iii) cause the Partnership to be treated as an association taxable as a corporation or otherwise to be taxed as an entity for U.S. federal income tax purposes (to the extent not already so treated or taxed).

(b) The General Partner may impose restrictions on the transfer of Partnership Interests if it receives an Opinion of Counsel that such restrictions are necessary or advisable to (i) avoid a significant risk of the Partnership becoming taxable as a corporation or otherwise becoming taxable as an entity for U.S. federal income tax purposes or (ii) preserve the uniformity of the Limited Partner Interests (or any class or series thereof). The General Partner may impose such restrictions by amending this Agreement; *provided*, *however*, that any amendment that would result in the delisting or suspension of trading of any class of Limited Partner Interests on the principal National Securities Exchange on which such class of Limited Partner Interests is then listed or admitted for trading must be approved, prior to such amendment being effected, by the holders of at least a majority of the Outstanding Limited Partner Interests of such class.

(c) Nothing contained in this Article IV or elsewhere in this Agreement shall preclude the settlement of any transactions involving Partnership Interests entered into through the facilities of any National Securities Exchange on which such Partnership Interests are listed or admitted for trading.

(d) In the event that any Partnership Interest is evidenced in certificated form, each such certificate shall bear a conspicuous legend in substantially the following form:

THE HOLDER OF THIS SECURITY ACKNOWLEDGES FOR THE BENEFIT OF ATLAS RESOURCE PARTNERS, L.P. THAT THIS SECURITY MAY NOT BE SOLD, OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED IF SUCH TRANSFER WOULD (A) VIOLATE THE THEN-APPLICABLE FEDERAL OR STATE SECURITIES LAWS OR RULES AND REGULATIONS OF THE SECURITIES AND EXCHANGE COMMISSION, ANY STATE SECURITIES COMMISSION OR ANY OTHER GOVERNMENTAL AUTHORITY WITH JURISDICTION OVER SUCH TRANSFER, (B) TERMINATE THE EXISTENCE OR QUALIFICATION OF ATLAS RESOURCE PARTNERS, L.P. UNDER THE LAWS OF THE STATE OF DELAWARE, OR (C) CAUSE ATLAS RESOURCE PARTNERS, L.P. TO BE TREATED AS AN ASSOCIATION TAXABLE AS A CORPORATION OR OTHERWISE TO BE TAXED AS AN ENTITY FOR U.S. FEDERAL INCOME TAX PURPOSES (TO THE EXTENT NOT ALREADY SO TREATED OR TAXED). ATLAS RESOURCE PARTNERS GP, LLC, THE GENERAL PARTNER OF ATLAS RESOURCE PARTNERS, L.P., MAY IMPOSE ADDITIONAL RESTRICTIONS ON THE TRANSFER OF THIS SECURITY IF IT RECEIVES AN OPINION OF COUNSEL THAT SUCH RESTRICTIONS ARE NECESSARY OR ADVISABLE TO AVOID A SIGNIFICANT RISK OF ATLAS RESOURCE PARTNERS, L.P. BECOMING TAXABLE AS A CORPORATION OR OTHERWISE BECOMING TAXABLE AS AN ENTITY FOR U.S. FEDERAL INCOME TAX PURPOSES OR TO PRESERVE THE UNIFORMITY OF THE LIMITED PARTNER INTERESTS (OR ANY CLASS OR SERIES THEREOF). THE RESTRICTIONS SET FORTH ABOVE SHALL NOT PRECLUDE THE SETTLEMENT OF ANY TRANSACTIONS INVOLVING THIS SECURITY ENTERED INTO THROUGH THE FACILITIES OF ANY NATIONAL SECURITIES EXCHANGE ON WHICH THIS SECURITY IS LISTED OR ADMITTED FOR TRADING.

SECTION 4.9. *Eligibility Certificates; Ineligible Holders*.

(a) If at any time the General Partner determines, with the advice of counsel, that:

(i) the Partnership's status other than as an association taxable as a corporation for U.S. federal income tax purposes or the failure of the Partnership otherwise to be subject to an entity-level tax for U.S. federal, state or local income tax purposes, coupled with the tax status (or lack of proof of the U.S. federal income tax status) of one or more Limited Partners, has or will reasonably likely have a material adverse effect on the maximum applicable rate that can be charged to customers by Subsidiaries of the Partnership (a "*Rate Eligibility Trigger*"); or

(ii) any Group Member is subject to any federal, state or local law or regulation that would create a substantial risk of cancellation or forfeiture of any property in which the Group Member has an interest based on the nationality, citizenship or other related status of a Limited Partner (a "*Citizenship Eligibility Trigger*");

then, in each of cases (i) and (ii), the General Partner may adopt such amendments to this Agreement as it determines to be necessary or advisable to (A) in the case of a Rate Eligibility Trigger, obtain such proof of the U.S. federal income tax status of the Limited Partners and, to the extent relevant, their beneficial owners, as the General Partner determines to be necessary or advisable to establish those Limited Partners whose U.S. federal income tax status does not or would not have a material adverse effect on the maximum applicable rate that can be charged to customers by any Group Member or (B) in the case of a Citizenship Eligibility Trigger, obtain such proof of the nationality, citizenship or other related status of the Partner (or, if the Partner is a nominee holding for the account of another Person, the nationality, citizenship or other related status of such Person) as the General Partner determines to be necessary or advisable to establish those Partners whose status as Partners does not or would not subject any Group Member to a significant risk of cancellation or forfeiture of any of its properties or interests therein.

(b) Such amendments may include provisions requiring all Limited Partners to certify as to their (and their beneficial owners') status as Eligible Holders upon demand and on a regular basis, as determined by the General Partner, and may require transferees of Units to so certify prior to being admitted to the Partnership as a Limited Partner (any such required certificate, an "*Eligibility Certificate*").

(c) Such amendments may provide that any Limited Partner (and its beneficial owners) who fails to furnish to the General Partner, within a reasonable period after a request, an Eligibility Certificate and any other information and proof of its (and its beneficial owners') status as an Eligible Holder, or if upon receipt of such Eligibility Certificate or other requested information the General Partner determines that a Limited Partner is not an Eligible Holder (such a Limited Partner, an "*Ineligible Holder*"), the Limited Partner Interests owned by such Limited Partner shall be subject to redemption in accordance with the provisions of Section 4.10. In addition, the General Partner shall be substituted for any Limited Partner that is an Ineligible Holder as the Limited Partner in respect of the Ineligible Holder's Limited Partner Interests.

(d) The General Partner shall, in exercising voting rights in respect of Partnership Interests held by it on behalf of Ineligible Holders, distribute the votes in the same ratios as the votes of Limited Partners (including the General Partner and its Affiliates) in respect of Limited Partner Interests other than those of Ineligible Holders are cast, either for, against or abstaining as to the matter.

(e) Upon dissolution of the Partnership, an Ineligible Holder shall have no right to receive a distribution in kind pursuant to Section 12.4 but shall be entitled to the cash equivalent thereof, and the Partnership shall provide cash in exchange for an assignment of the Ineligible Holder's share of any distribution in kind. Such payment and assignment shall be treated for Partnership purposes as a purchase by the Partnership from the Ineligible Holder of its Limited Partner Interest (representing the right to receive its share of such distribution in kind).

(f) At any time after a holder can and does certify that it has become an Eligible Holder, an Ineligible Holder may, upon application to the General Partner, request that with respect to any Limited Partner Interests of such Ineligible Holder not redeemed pursuant to Section 4.10, such Ineligible Holder, upon approval of the General Partner, shall no longer constitute an Ineligible Holder, and the General Partner shall cease to be deemed to be the Limited Partner in respect of such Ineligible Holder's Limited Partner Interests.

SECTION 4.10. *Redemption of Partnership Interests of Ineligible Holders*.

(a) If at any time a Limited Partner fails to furnish an Eligibility Certificate or any other information requested within the period of time specified in amendments adopted pursuant to Section 4.9, or if upon receipt of such Eligibility Certificate or other information the General Partner determines, with the advice of counsel, that a Limited Partner is not an Eligible Holder, the Partnership may, unless the Limited Partner establishes to the satisfaction of the General Partner that such Limited Partner is an Eligible Holder or has transferred its Limited Partner Interests to a Person who is an Eligible Holder and who furnishes an Eligibility Certificate to the General Partner prior to the date fixed for redemption as provided below, redeem the Limited Partner Interest of such Limited Partner as follows:

(i) The General Partner shall, not later than the 30th day before the date fixed for redemption, give notice of redemption to the Limited Partner, at its last address designated on the records of the Partnership or the Transfer Agent, as applicable, by registered or certified mail, postage prepaid. The notice shall be deemed to have been given when so mailed. The notice shall specify the Redeemable Interests, the date fixed for redemption, the place of payment, that payment of the redemption price will be made upon redemption of the Redeemable Interests (or, if later in the case of Redeemable Interests evidenced by Certificates, upon surrender of the Certificate evidencing the Redeemable Interests) and that on and after the date fixed for redemption no further allocations or distributions to which the Limited Partner would otherwise be entitled in respect of the Redeemable Interests will accrue or be made.

(ii) The aggregate redemption price for Redeemable Interests shall be an amount equal to the Current Market Price (the date of determination of which shall be the date fixed for redemption) of Partnership Interests of the class to be so redeemed multiplied by the number of Partnership Interests of each such class included among the Redeemable Interests. The redemption price shall be paid, as determined by the General Partner, in cash or by delivery of a promissory note of the Partnership in the principal amount of the redemption price, bearing interest at the rate of 5% annually and payable in three equal annual installments of principal together with accrued interest, commencing one year after the redemption date.

(iii) The Limited Partner or his duly authorized representative shall be entitled to receive the payment for the Redeemable Interests at the place of payment specified in the notice of redemption on the redemption date (or, if later in the case of Redeemable Interests evidenced by Certificates, upon surrender by or on behalf of the Limited Partner at the place specified in the notice of redemption, of the Certificate evidencing the Redeemable Interests, duly endorsed in blank or accompanied by an assignment duly executed in blank).

(iv) After the redemption date, Redeemable Interests shall no longer constitute issued and Outstanding Partnership Interests.

(b) The provisions of this Section 4.10 shall also be applicable to Partnership Interests held by a Limited Partner as nominee of a Person determined to be an Ineligible Holder.

(c) Nothing in this Section 4.10 shall prevent the recipient of a notice of redemption from transferring its Partnership Interest before the redemption date if such transfer is otherwise permitted under this Agreement. Upon receipt of notice of such a transfer, the General Partner shall withdraw the notice of redemption; *provided* the transferee of such Partnership Interest certifies to the satisfaction of the General Partner that it is an Eligible Holder. If the transferee fails to make such certification, such redemption shall be effected from the transferee on the original redemption date.

ARTICLE V

CAPITAL CONTRIBUTIONS
AND ISSUANCE OF PARTNERSHIP INTERESTS

SECTION 5.1. *Organizational Contributions.*

In connection with the formation of the Partnership under the Delaware Act, the General Partner made an initial Capital Contribution to the Partnership in the amount of $20.00 in exchange for a General Partner Interest consisting of Class A Units representing a Percentage Interest of 2%, and was admitted as the General Partner of the Partnership. The Organizational Limited Partner made an initial Capital Contribution to the Partnership in the amount of $980.00 in exchange for a Limited Partner Interest consisting of Common Units representing a Percentage Interest of 98%, and was admitted as a Limited Partner of the Partnership.

SECTION 5.2. *Additional Capital Contributions.*

(a) Prior to the date of this Agreement, the Organizational Limited Partner and the General Partner contributed to the Partnership, as a Capital Contribution, cash and ownership interest in the Transferred Assets (as defined in the Separation Agreement) and the Transferred Liabilities (as defined in the Separation Agreement), in exchange for Common Units, Class A Units and the Incentive Distribution Rights, so that, after such Capital Contribution, (i) the General Partner held (A) 534,694 Class A Units, representing a General Partner Interest with a Percentage Interest of 2%, subject to all of the rights, privileges and duties of the General Partner under this Agreement, and (B) the Incentive Distribution Rights; and (ii) the Organizational Limited Partner held 26,200,000 Common Units, representing a Limited Partner Interest with a Percentage Interest of 98%.

(b) No Limited Partner will be required by this Agreement to make any additional Capital Contribution to the Partnership.

SECTION 5.3. *Interest and Withdrawal.*

No interest on Capital Contributions shall be paid by the Partnership. No Partner shall be entitled to the withdrawal or return of its Capital Contribution, except to the extent, if any, that distributions made pursuant to this Agreement or upon liquidation of the Partnership may be considered as such by law and then only to the extent provided for in this Agreement. Except to the extent expressly provided in this Agreement, no Partner shall have priority over any other Partner either as to the return of Capital Contributions or as to profits, losses or distributions. Any such return shall be a compromise to which all Partners agree within the meaning of Section 17-502(b) of the Delaware Act.

SECTION 5.4. *Capital Accounts.*

(a) The Partnership shall maintain for each Partner (or a beneficial owner of Partnership Interests held by a nominee in any case in which the nominee has furnished the identity of such owner to the Partnership in accordance with Section 6031(c) of the Code or any other method acceptable to the General Partner) owning a Partnership Interest a separate Capital Account with respect to such Partnership Interest in accordance with the rules of Treasury Regulation Section 1.704-1(b)(2)(iv). Such Capital Account shall be increased by (i) the amount of all Capital Contributions made to the Partnership with respect to such Partnership Interest and (ii) all items of Partnership income and gain (including Simulated Gain and income and gain exempt from tax) computed in accordance with Section 5.4(b) and allocated with respect to such Partnership Interest pursuant to Section 6.1, and decreased by (x) the amount of cash or Net Agreed Value of all actual and deemed distributions of cash or property made with respect to such Partnership Interest and (y) all items of Partnership deduction and loss (including Simulated Depletion and Simulated Loss) computed in accordance with Section 5.4(b) and allocated with respect to such Partnership Interest pursuant to Section 6.1.

(b) For purposes of computing the amount of any item of income, gain, loss, deduction, Simulated Depletion, Simulated Gain or Simulated Loss to be allocated pursuant to Article VI and to be reflected in the Partners' Capital Accounts, the determination, recognition and classification of any such item shall be the same as its determination, recognition and classification for U.S. federal income tax purposes (including any method of depreciation, cost recovery or amortization used for that purpose); *provided* that:

(i) Solely for purposes of this Section 5.4, the Partnership shall be treated as owning directly its proportionate share (as determined by the General Partner based upon the provisions of the applicable governing, organizational or similar documents) of all property owned by (x) any other Group Member that is classified as a partnership for U.S. federal income tax purposes and (y) any other partnership, limited liability company, unincorporated business or other entity classified as a partnership for U.S. federal income tax purposes of which a Group Member is, directly or indirectly, a partner, member or other equity holder.

(ii) All fees and other expenses incurred by the Partnership to promote the sale of (or to sell) a Partnership Interest that can neither be deducted nor amortized under Section 709 of the Code, if any, shall, for purposes of Capital Account maintenance, be treated as an item of deduction at the time such fees and other expenses are incurred and shall be allocated among the Partners pursuant to Section 6.1.

(iii) Except as otherwise provided in Treasury Regulation Section 1.704-1(b)(2)(iv)(m), the computation of all items of income, gain, loss, deduction, Simulated Depletion, Simulated Gain and Simulated Loss shall be made without regard to any election under Section 754 of the Code that may be made by the Partnership and, as to those items described in Section 705(a)(1)(B) or 705(a)(2)(B) of the Code, without regard to the fact that such items are not includable in gross income or are neither currently deductible nor capitalized for U.S. federal income tax purposes. To the extent an adjustment to the adjusted tax basis of any Partnership asset pursuant to Section 734(b) or 743(b) of the Code is required, pursuant to Treasury Regulation Section 1.704-1(b)(2)(iv)(m), to be taken into account in determining Capital Accounts, the amount of such adjustment in the Capital Accounts shall be treated as an item of gain or loss.

(iv) Any income, gain, loss, Simulated Gain, Simulated Loss or deduction attributable to the taxable disposition of any Partnership property shall be determined as if the adjusted basis of such property as of such date of disposition were equal in amount to the Partnership's Carrying Value with respect to such property as of such date.

(v) Any item of income of the Partnership that is described in Section 705(a)(1)(B) of the Code (with respect to items of income that are exempt from tax) shall be treated as an item of income for the purpose of this Section 5.4(b), and any item of expense of the Partnership that is described in Section 705(a)(2)(B) of the Code (with respect to expenditures that are not deductible and not chargeable to capital accounts) shall be treated as an item of deduction for the purpose of this Section 5.4(b), in each case without regard to the fact that such items are not includable in gross income or are neither currently deductible nor capitalized for U.S. federal income tax purposes.

(vi) In accordance with the requirements of Section 704(b) of the Code, any deductions for depreciation, cost recovery, amortization or Simulated Depletion attributable to any Contributed Property shall be determined as if the adjusted basis of such property on the date it was acquired by the Partnership were equal to the Agreed Value of such property. Upon an adjustment pursuant to Section 5.4(d) to the Carrying Value of any Partnership property subject to depreciation, cost recovery, amortization, or Simulated Depletion, any further deductions for such depreciation, cost recovery, amortization or Simulated Depletion attributable to such property shall be determined (A) as if the adjusted basis of such property were equal to the Carrying Value of such property immediately following such adjustment and (B) using a rate of depreciation, cost recovery or amortization derived from the same method and useful life (or, if applicable, the remaining useful life) as is applied for U.S. federal income tax purposes; *provided*, *however*, that, if the asset has a zero adjusted basis for U.S. federal income tax purposes, depreciation, cost recovery or amortization deductions shall be determined using any method that the General Partner may adopt.

(vii) The Gross Liability Value of each Liability of the Partnership described in Treasury Regulation Section 1.752-7(b)(3)(i) shall be adjusted at such times as provided in this Agreement for an adjustment to Carrying Values. The amount of any such adjustment shall be treated for purposes hereof as an item of loss (if the adjustment increases the Carrying Value of such Liability of the Partnership) or an item of gain (if the adjustment decreases the Carrying Value of such Liability of the Partnership).

(viii) If the Partnership's adjusted basis in a depreciable or cost recovery property is reduced for U.S. federal income tax purposes pursuant to Section 50(c)(1) or (3) of the Code, the amount of such reduction shall, solely for purposes hereof, be deemed to be an additional depreciation or cost recovery deduction in the year such property is placed in service and shall be allocated among the Partners pursuant to Section 6.1. Any restoration of such basis pursuant to Section 50(c)(2) of the Code shall, to the extent possible, be allocated in the same manner to the Partners to whom such deemed deduction was allocated.

(c) A transferee of a Partnership Interest shall succeed to a pro rata portion of the Capital Account of the transferor relating to the Partnership Interest so transferred.

(d) (i) In accordance with Treasury Regulation Section 1.704-1(b)(2)(iv)(f), on an issuance of additional Partnership Interests for cash or Contributed Property, the issuance of Partnership Interests as consideration for the provision of services or the conversion of the General Partner's Combined Interest to Common Units pursuant to Section 11.3(b), the Capital Account of all Partners and the Carrying Value of each Partnership property immediately prior to such issuance shall be adjusted upward or downward to reflect any Unrealized Gain or Unrealized Loss attributable to such Partnership property, as if such Unrealized Gain or Unrealized Loss had been recognized on an actual sale of each such property for an amount equal to its fair market value immediately prior to such issuance and had been allocated among the Partners at such time pursuant to Section 6.1 in the same manner as any item of gain or loss actually recognized during such period would have been allocated; *provided*, *however*, that in the event of an issuance of Partnership Interests for a *de minimis* amount of cash or Contributed Property, or in the event of an issuance of a *de minimis* amount of Partnership Interests as consideration for the provision of services, the General Partner may determine that such adjustments are unnecessary for the proper administration of the Partnership. In determining such Unrealized Gain or Unrealized Loss for purposes of maintaining Capital Accounts, the aggregate fair market value of all Partnership property (including cash or cash equivalents) immediately prior to the issuance of additional Partnership Interests shall be determined by the General Partner using such method of valuation as it may adopt; *provided*, *however*, that the General Partner, in arriving at such valuation, may determine that it is appropriate to first determine an aggregate value for the Partnership, derived from the current trading price of the Common Units, and taking fully into account the fair market value of the Partnership Interests of all Partners at such time. The General Partner shall allocate such aggregate value among the assets of the Partnership (in such manner as it determines) to arrive at a fair market value for individual properties.

(ii) In accordance with Treasury Regulation Section 1.704-1(b)(2)(iv)(f), immediately prior to any actual or deemed distribution to a Partner of any Partnership property (other than a distribution of cash that is not in redemption or retirement of a Partnership Interest), the Capital Accounts of all Partners and the Carrying Value of all Partnership property shall be adjusted upward or downward to reflect any Unrealized Gain or Unrealized Loss attributable to such Partnership property, as if such Unrealized Gain or Unrealized Loss had been recognized in a sale of such property immediately prior to such distribution for an amount equal to its fair market value, and had been allocated among the Partners, at such time, pursuant to Section 6.1 in the same manner as any item of gain, loss, Simulated Gain or Simulated Loss actually recognized during such period would have been allocated; *provided*, *however*, that in the event of a distribution of a *de minimis* amount of Partnership property, the General Partner may determine that such adjustments are unnecessary for the proper administration of the Partnership. In determining such Unrealized Gain or Unrealized Loss for purposes of maintaining Capital Accounts, the aggregate fair market value of all Partnership assets (including cash or cash equivalents) immediately prior to a distribution shall

(A) in the case of an actual distribution that is not made pursuant to Section 12.4 or in the case of a deemed distribution, be determined in the same manner as that provided in Section 5.4(d)(i), or (B) in the case of a liquidating distribution pursuant to Section 12.4, be determined and allocated by the Liquidator using such method of valuation as it may adopt.

SECTION 5.5. *Issuances of Additional Partnership Interests*.

(a) The Partnership may issue additional Partnership Interests and options, rights, warrants and appreciation rights relating to the Partnership Interests for any Partnership purpose at any time and from time to time to such Persons for such consideration and on such terms and conditions as the General Partner shall determine, all without the approval of any Limited Partners.

(b) Each additional Partnership Interest authorized to be issued by the Partnership pursuant to Section 5.5(a) may be issued in one or more classes, or one or more series of any such classes, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of Partnership Interests), as shall be fixed by the General Partner, including (i) the right to share in Partnership profits and losses or items thereof; (ii) the right to share in Partnership distributions; (iii) the rights upon dissolution and liquidation of the Partnership; (iv) whether, and the terms and conditions upon which, the Partnership may or shall be required to redeem the Partnership Interest (including sinking fund provisions); (v) whether such Partnership Interest is issued with the privilege of conversion or exchange and, if so, the terms and conditions of such conversion or exchange; (vi) the terms and conditions upon which each Partnership Interest will be issued, evidenced by certificates and assigned or transferred; (vii) the method for determining the Percentage Interest as to such Partnership Interest; and (viii) the right, if any, of each such Partnership Interest to vote on Partnership matters, including matters relating to the relative designations, preferences, rights, powers and duties of such Partnership Interest.

(c) The General Partner is hereby authorized and directed to take all actions that it determines to be necessary or appropriate in connection with (i) each issuance of Partnership Interests and options, rights, warrants and appreciation rights relating to Partnership Interests pursuant to this Section 5.5, (ii) the conversion of the Combined Interest into Common Units pursuant to the terms of this Agreement, (iii) the admission of Additional Limited Partners and (iv) all additional issuances of Partnership Interests. The General Partner shall determine the relative rights, powers and duties of the holders of the Units or other Partnership Interests being so issued. The General Partner shall do all things necessary to comply with the Delaware Act and is authorized and directed to do all things that it determines to be necessary or appropriate in connection with any future issuance of Partnership Interests or in connection with the conversion of the Combined Interest into Common Units pursuant to the terms of this Agreement, including compliance with any statute, rule, regulation or guideline of any federal, state or other governmental agency or any National Securities Exchange on which the Units or other Partnership Interests are listed or admitted for trading.

(d) No fractional Units shall be issued by the Partnership. If a distribution, subdivision or combination of Units would result in the issuance of fractional Units (but for this Section 5.5(d)), then each fractional Unit shall be rounded to the nearest whole Unit (and a 0.5 Unit shall be rounded to the next higher Unit).

SECTION 5.6. *Limited Preemptive Rights*.

Except as provided in this Section 5.6 and in Section 5.10 or as otherwise provided in a separate agreement by the Partnership, no Person shall have any preemptive, preferential or other similar right with respect to the issuance of any Partnership Interest, whether unissued, held in the treasury or hereafter created; *provided* that the General Partner shall have the right, which it may from time to time assign in whole or in part to any of its Affiliates, to purchase or subscribe for Partnership Interests from the Partnership whenever, and on the same terms that, the Partnership issues Partnership Interests to any Persons, to the extent necessary so that the aggregate Percentage Interests of the General Partner and its Affiliates, taken together, immediately after such issuances (including any issuance pursuant to the exercise of the rights described in this proviso) equals the aggregate Percentage Interests of the General Partner and its Affiliates, taken together, immediately prior to such issuances.

SECTION 5.7. *Splits and Combinations*.

(a) Subject to Section 5.5(d), Section 6.6 and Section 6.8 (dealing with adjustments of distribution levels), the Partnership may make a Pro Rata distribution of Partnership Interests to all Record Holders or may effect a subdivision or combination of Partnership Interests so long as, after any such event, each Partner shall have the same Percentage Interest in the Partnership as before such event, and any amounts calculated on a per Partnership Interest basis or stated as a number of Partnership Interests are proportionately adjusted.

(b) Whenever such a distribution, subdivision or combination of Partnership Interests is declared, the General Partner shall select a Record Date as of which the distribution, subdivision or combination shall be effective and shall send notice thereof at least 20 days prior to such Record Date to each Record Holder as of a date not less than 10 days prior to the date of such notice. The General Partner also may cause a firm of independent public accountants selected by it to calculate the number of Partnership Interests to be held by each Record Holder after giving effect to such distribution, subdivision or combination. The General Partner shall be entitled to rely on any certificate provided by such firm as conclusive evidence of the accuracy of such calculation.

(c) Promptly following any such distribution, subdivision or combination, the Partnership may issue Certificates or uncertificated Partnership Interests to the Record Holders of Partnership Interests as of the applicable Record Date representing the new number of Partnership Interests held by such Record Holders, or the General Partner may adopt such other procedures that it determines to be necessary or appropriate to reflect such changes. If any such combination results in a smaller total number of Partnership Interests Outstanding, and a Partnership Interest is represented by a Certificate, the Partnership shall require, as a condition to the delivery to a Record Holder of such new Certificate, the surrender of any Certificate held by such Record Holder immediately prior to such Record Date.

SECTION 5.8. *Fully Paid and Non-Assessable Nature of Limited Partner Interests*.

All Limited Partner Interests issued pursuant to, and in accordance with the requirements of, this Article V shall be fully paid and non-assessable Limited Partner Interests in the Partnership, except as such non-assessability may be affected by Section 17-607 or 17-804 of the Delaware Act.

SECTION 5.9. *Issuance of Common Units in Connection with Reset of Incentive Distribution Rights*.

(a) Subject to the provisions of this Section 5.9, the holder of the Incentive Distribution Rights (or, if there is more than one holder of the Incentive Distribution Rights, the holders of a majority in interest of the Incentive Distribution Rights) shall have the right, at any time when the Partnership has made a distribution pursuant to Section 6.4(a)(v) for each of the four most recently completed Quarters and the amount of each such distribution did not exceed Adjusted Operating Surplus for such Quarter, to make an election (the "*IDR Reset Election*") to cause the Minimum Quarterly Distribution and the Target Distributions to be reset in accordance with the provisions of Section 5.9(e). Upon the exercise of the IDR Reset Election, the holder or holders of the Incentive Distribution Rights will become entitled to receive an aggregate number of Common Units (the "*IDR Reset Common Units*") equal to the quotient (such quotient, the "*Aggregate Quantity of IDR Reset Common Units*") obtained by dividing (i) the average amount of cash distributions made by the Partnership for the two full Quarters immediately preceding the giving of the Reset Notice (as defined in Section 5.9(b)) in respect of the Incentive Distribution Rights by (ii) the average of the cash distributions made by the Partnership in respect of each Common Unit for the two full Quarters immediately preceding the giving of the Reset Notice (such average of cash distributions described in this clause (ii), the "*Reset MQD*"). If, at the time of any IDR Reset Election, the

General Partner and its Affiliates are not the holders of a majority in interest of the Incentive Distribution Rights, then the IDR Reset Election shall be subject to the prior written concurrence of the General Partner that the conditions described in the immediately previous sentence have been satisfied. The making of the IDR Reset Election in the manner specified in Section 5.9(b) shall cause the Minimum Quarterly Distribution and the Target Distributions to be reset in accordance with the provisions of Section 5.9(e) and, in connection therewith, the holder or holders of the Incentive Distribution Rights will become entitled to receive the Aggregate Quantity of IDR Reset Common Units on the basis specified above, without any further approval required by the General Partner (other than as set forth in the prior sentence of this Section 5.9(a)) and without any approval of the Unitholders, at the time specified in Section 5.9(c) unless the IDR Reset Election is rescinded pursuant to Section 5.9(d).

(b) To exercise the right specified in Section 5.9(a), the holder of the Incentive Distribution Rights (or, if there is more than one holder of the Incentive Distribution Rights, the holders of a majority in interest of the Incentive Distribution Rights) shall deliver a written notice (the "*Reset Notice*") to the Partnership. Within 10 Business Days after the receipt by the Partnership of such Reset Notice, the Partnership shall deliver a written notice to the holder or holders of the Incentive Distribution Rights of the Partnership's determination of the aggregate number of Common Units that each holder of Incentive Distribution Rights will be entitled to receive.

(c) The holder or holders of the Incentive Distribution Rights will be entitled to receive the Aggregate Quantity of IDR Reset Common Units and the General Partner will be entitled to receive the related additional Class A Units pursuant to Section 5.10 on the 15th Business Day after receipt by the Partnership of the Reset Notice; *provided*, *however*, that the issuance of IDR Reset Common Units to the holder or holders of the Incentive Distribution Rights shall not occur prior to the approval of the listing or admission for trading of such IDR Reset Common Units by the principal National Securities Exchange upon which the Common Units are then listed or admitted for trading if any such approval is required pursuant to the rules and regulations of such National Securities Exchange.

(d) If the principal National Securities Exchange upon which the Common Units are then traded has not approved the listing or admission for trading of the IDR Reset Common Units to be issued pursuant to this Section 5.9 on or before the 30th calendar day following the Partnership's receipt of the Reset Notice and such approval is required by the rules and regulations of such National Securities Exchange, then the holder of the Incentive Distribution Rights (or, if there is more than one holder of the Incentive Distribution Rights, the holders of a majority in interest of the Incentive Distribution Rights) shall have the right to either rescind the IDR Reset Election or elect to receive other Partnership Interests having such terms as the General Partner may approve, that will provide (i) the same economic value, in the aggregate, as the Aggregate Quantity of IDR Reset Common Units would have had at the time of the Partnership's receipt of the Reset Notice, as determined by the General Partner, and (ii) for the subsequent conversion of such Partnership Interests into Common Units within not more than 12 months following the Partnership's receipt of the Reset Notice upon the satisfaction of one or more conditions that are reasonably acceptable to the holder of the Incentive Distribution Rights (or, if there is more than one holder of the Incentive Distribution Rights, the holders of a majority in interest of the Incentive Distribution Rights).

(e) The Minimum Quarterly Distribution and the Target Distributions shall be adjusted at the time of the issuance of Common Units or other Partnership Interests pursuant to this Section 5.9 such that (i) the Minimum Quarterly Distribution shall be reset to equal to the Reset MQD, (ii) the First Target Distribution shall be reset to equal 115% of the Reset MQD, (iii) the Second Target Distribution shall be reset to equal 125% of the Reset MQD and (iv) the Third Target Distribution shall be reset to equal 150% of the Reset MQD.

(f) Upon the issuance of IDR Reset Common Units pursuant to Section 5.9(a), the Capital Account maintained with respect to the Incentive Distribution Rights shall (i) first, be allocated to IDR Reset Common Units in an amount equal to the product of (A) the Aggregate Quantity of IDR Reset Common Units and (B) the Per Unit Capital Amount for an Initial Common Unit, and (ii) second, any remaining balance in such Capital

Account will be retained by the holder of the Incentive Distributions Rights. In the event that there is not a sufficient Capital Account associated with the Incentive Distribution Rights to allocate the full Per Unit Capital Amount for an Initial Common Unit to the IDR Reset Common Units in accordance with clause (i) of this Section 5.9(f), the IDR Reset Common Units shall be subject to Section 6.1(d)(x)(A) and Section 6.1(d)(x)(B).

SECTION 5.10. *No Additional Capital Contributions by the General Partner or Dilution; Automatic Issuance of Class A Units Upon Issuance of Units*.

(a) The Percentage Interest represented by all of the Outstanding Class A Units shall at all times be equal to 2%, regardless of any issuance of any Limited Partner Interests or Units by the Partnership, and the General Partner shall not be obligated to make any capital contribution to the Partnership in order for such Class A Units to represent such Percentage Interest.

(b) The parties intend that each Class A Unit shall represent the same Percentage Interest as one Unit. Accordingly, upon issuance of any Limited Partner Interests or Units by the Partnership (including any IDR Reset Common Units, but excluding the issuance of Common Units pursuant to Section 5.2(a)), the Partnership will automatically issue to the General Partner, without further consideration or any requirement of capital contribution by the General Partner, a number of Class A Units so that the total number of Outstanding Class A Units after such issuance equals 2% of the sum of (i) the total number of Outstanding Units after such issuance and (ii) the total number of Outstanding Class A Units after such issuance.

ARTICLE VI

ALLOCATIONS AND DISTRIBUTIONS

SECTION 6.1. *Allocations for Capital Account Purposes*.

For purposes of maintaining the Capital Accounts and in determining the rights of the Partners among themselves, the Partnership's items of income, gain, loss, deduction, Simulated Depletion, Simulated Gain and Simulated Loss (computed in accordance with Section 5.4(b)) shall be allocated among the Partners in each taxable year (or portion thereof) as provided herein below.

(a) *Net Income*. After giving effect to the special allocations set forth in Section 6.1(d), and any allocations to other Partnership Interests, Net Income for each taxable year and all items of income, gain, loss, deduction and Simulated Gain taken into account in computing Net Income for such taxable year shall be allocated to the Partners as follows:

(i) First, 100% to the General Partner in an amount equal to the aggregate Net Losses allocated to the General Partner pursuant to Section 6.1(b)(iii) for all previous taxable years until the aggregate Net Income allocated to the General Partner pursuant to this Section 6.1(a)(i) for the current taxable year and all previous taxable years is equal to the aggregate Net Losses allocated to the General Partner pursuant to Section 6.1(b)(iii) for all previous taxable years;

(ii) Second, 100% to the General Partner and the Unitholders, in accordance with their respective Percentage Interests, until the aggregate Net Income allocated to such Partners pursuant to this Section 6.1(a)(ii) for the current taxable year and all previous taxable years is equal to the aggregate Net Losses allocated to such Partners pursuant to Section 6.1(b)(ii) for all previous taxable years; and

(iii) Third, the balance, if any, 100% to the General Partner and the Unitholders in accordance with their respective Percentage Interests.

(b) *Net Losses*. After giving effect to the special allocations set forth in Section 6.1(d), and any allocations to other Partnership Interests, Net Losses for each taxable period and all items of income, gain, loss, deduction and Simulated Gain taken into account in computing Net Losses for such taxable period shall be allocated to the Partners as follows:

(i) First, 100% to the Unitholders, Pro Rata, until the aggregate Net Losses allocated pursuant to this Section 6.1(b)(i) for the current taxable year and all previous taxable years is equal to the aggregate Net Income allocated to such Partners pursuant to Section 6.1(a)(iii) for all previous taxable years, *provided* that the Net Losses shall not be allocated pursuant to this Section 6.1(b)(i) to the extent that such allocation would cause any Unitholder to have a deficit balance in its Adjusted Capital Account at the end of such taxable year (or increase any existing deficit balance in its Adjusted Capital Account);

(ii) Second, 100% to the Unitholders, Pro Rata; *provided*, that Net Losses shall not be allocated pursuant to this Section 6.1(b)(ii) to the extent that such allocation would cause any Unitholder to have a deficit balance in its Adjusted Capital Account at the end of such taxable year (or increase any existing deficit balance in its Adjusted Capital Account); and

(iii) Third, the balance, if any, 100% to the General Partner.

(c) *Net Termination Gains and Losses*. After giving effect to the special allocations set forth in Section 6.1(d), all items of income, gain, loss, deduction and Simulated Gain taken into account in computing Net Termination Gain or Net Termination Loss for such taxable period shall be allocated in the same manner as such Net Termination Gain or Net Termination Loss is allocated hereunder. All allocations under this Section 6.1(c) shall be made after Capital Account balances have been adjusted by all other allocations provided under this Section 6.1 and after all distributions of Available Cash provided under Sections 6.4 and 6.5 have been made; *provided*, *however*, that solely for purposes of this Section 6.1(c), Capital Accounts shall not be adjusted for distributions made pursuant to Section 12.4.

(i) If a Net Termination Gain is recognized (or deemed recognized pursuant to Section 5.4(d)), such Net Termination Gain shall be allocated among the Partners in the following manner (and the Capital Accounts of the Partners shall be increased by the amount so allocated in each of the following subclauses, in the order listed, before an allocation is made pursuant to the next succeeding subclause):

(A) First, to each Partner having a deficit balance in its Capital Account, in the proportion that such deficit balance bears to the total deficit balances in the Capital Accounts of all Partners, until each such Partner has been allocated Net Termination Gain equal to any such deficit balance in its Capital Account;

(B) Second, (x) 2% to the holders of Class A Units, Pro Rata, and (y) 98% to the holders of Common Units, Pro Rata, until the Capital Account in respect of each Common Unit then Outstanding is equal to (1) its Unrecovered Capital plus (2) the Minimum Quarterly Distribution for the Quarter during which the Liquidation Date occurs, reduced by any distribution pursuant to Section 6.4(a)(i) with respect to such Common Unit for such Quarter (the amount determined pursuant to this clause (2) is hereinafter defined as the "*Unpaid MQD*");

(C) Third, (x) 2% to the holders of Class A Units, Pro Rata, and (y) 98% to the holders of Common Units, Pro Rata, until the Capital Account in respect of each Common Unit then Outstanding is equal to the sum of (1) its Unrecovered Capital, (2) the Unpaid MQD and (3) the excess, if any, of (a) the First Target Distribution less the Minimum Quarterly Distribution for each Quarter of the Partnership's existence over (b) the cumulative per Unit amount of any distributions of Available Cash that is deemed to be Operating Surplus made pursuant to Section 6.4(a)(ii) (the sum of (1) plus (2) plus (3) is hereinafter defined as the "*First Liquidation Target Amount*");

(D) Fourth, (x) 2% to the holders of Class A Units, Pro Rata, (y) 85% to the holders of Common Units, Pro Rata, and 13% to the holders of the Incentive Distribution Rights, Pro Rata, until the Capital Account in respect of each Common Unit then Outstanding is equal to the sum of (1) the First Liquidation Target Amount and (2) the excess, if any, of (a) the Second Target Distribution less the First Target Distribution for each Quarter of the Partnership's existence over (b) the cumulative per Unit amount of any distributions of Available Cash that is deemed to be Operating Surplus made pursuant to Section 6.4(a)(iii) (the sum of (1) plus (2) is hereinafter defined as the "*Second Liquidation Target Amount*"); and

(E) Fifth, (x) 2% to the holders of Class A Units, Pro Rata, (y) 75% to the holders of Common Units, Pro Rata, and (z) 23% to the holders of the Incentive Distribution Rights, Pro Rata, until the Capital Account in respect of each Common Unit then Outstanding is equal to the sum of (1) the Second Liquidation Target Amount and (2) the excess, if any, of (a) the Third Target Distribution less the Second Target Distribution for each Quarter of the Partnership's existence over (b) the cumulative per Unit amount of any distributions of Available Cash that is deemed to be Operating Surplus made pursuant to Section 6.4(a)(iv); and

(F) Thereafter, (x) 2% to the holders of Class A Units, Pro Rata, (y) 50% to the holders of Common Units, Pro Rata, and (z) 48% to the holders of the Incentive Distribution Rights, Pro Rata.

(ii) If a Net Termination Loss is recognized (or deemed recognized pursuant to Section 5.4(d)), such Net Termination Loss shall be allocated among the Partners in the following manner:

(A) First, 2% to the holders of Class A Units, Pro Rata, and 98% to the holders of Common Units, Pro Rata, until the Capital Account in respect of each Common Unit then Outstanding has been reduced to zero; and

(B) Second, the balance, if any, 100% to the General Partner.

(d) *Special Allocations*. Notwithstanding any other provision of this Section 6.1, the following special allocations shall be made for such taxable period:

(i) *Partnership Minimum Gain Chargeback*. Notwithstanding any other provision of this Section 6.1, if there is a net decrease in Partnership Minimum Gain during any Partnership taxable period, each Partner shall be allocated items of Partnership income and gain for such period (and, if necessary, subsequent periods) in the manner and amounts provided in Treasury Regulation Sections 1.704-2(f)(6), 1.704-2(g)(2) and 1.704-2(j)(2)(i), or any successor provision. For purposes of this Section 6.1(d), each Partner's Adjusted Capital Account balance shall be determined, and the allocation of income, gain or Simulated Gain required hereunder shall be effected, prior to the application of any other allocations pursuant to this Section 6.1(d) with respect to such taxable period (other than an allocation pursuant to Sections 6.1(d)(vi) and 6.1(d)(vii)). This Section 6.1(d)(i) is intended to comply with the Partnership Minimum Gain chargeback requirement in Treasury Regulation Section 1.704-2(f) and shall be interpreted consistently therewith.

(ii) *Chargeback of Partner Nonrecourse Debt Minimum Gain*. Notwithstanding the other provisions of this Section 6.1 (other than Section 6.1(d)(i)), except as provided in Treasury Regulation Section 1.704-2(i)(4), if there is a net decrease in Partner Nonrecourse Debt Minimum Gain during any Partnership taxable period, any Partner with a share of Partner Nonrecourse Debt Minimum Gain at the beginning of such taxable period shall be allocated items of Partnership income, gain and Simulated Gain for such period (and, if necessary, subsequent periods) in the manner and amounts provided in Treasury Regulation Sections 1.704-2(i)(4) and 1.704-2(j)(2)(ii), or any successor provisions. For purposes of this Section 6.1(d), each Partner's Adjusted Capital Account balance shall be determined, and the allocation of income, gain or Simulated Gain required hereunder shall be effected, prior to the application of any other allocations pursuant to this Section 6.1(d), other than Section 6.1(d)(i) and other than an allocation pursuant to Sections 6.1(d)(vi) and 6.1(d)(vii), with respect to such taxable period. This Section 6.1(d)(ii) is intended to comply with the chargeback of items of income and gain requirement in Treasury Regulation Section 1.704-2(i)(4) and shall be interpreted consistently therewith.

(iii) *Priority Allocations*.

(A) If the amount of cash or the Net Agreed Value of any property distributed (except cash or property distributed pursuant to Section 12.4) to any Unitholder with respect to its Units or Class A Units, as the case may be for a taxable year is greater (on a per Unit basis or per Class A Unit basis, as the case may be) than the amount of cash or the Net Agreed Value of property distributed to the other Unitholders with respect to their Units or Class A Units, as the case may be (on a per Unit basis or a per Class A Unit basis, as the case may be), then each Unitholder receiving such greater cash or property distribution shall be allocated gross income in an amount equal to the product of (1) the amount by which the distribution (on a per Unit basis or per Class A Unit basis, as the case may be) to such Unitholder exceeds the distribution (on a per Unit basis or per Class A Unit basis, as the case may be) to the Unitholders receiving the smallest distribution and (2) the number of Units or Class A Units, as the case may be, owned by the Unitholder receiving the greater distribution.

(B) After the application of Section 6.1(d)(iii)(A), all or any portion of the remaining items of Partnership gross income or gain for the taxable period, if any, shall be allocated 100% to the holders of Incentive Distribution Rights, Pro Rata, until the aggregate amount of such items allocated to the holders of Incentive Distribution Rights pursuant to this Section 6.1(d)(iii)(B) for the current taxable year and all previous taxable years is equal to the cumulative amount of all Incentive Distributions made to the holders of Incentive Distribution Rights from the Closing Date to a date 45 days after the end of the current taxable year.

(iv) *Qualified Income Offset*. In the event any Partner unexpectedly receives any adjustments, allocations or distributions described in Treasury Regulation Section 1.704-1(b)(2)(ii)(d)(4), 1.704-1(b)(2)(ii)(d)(5) or 1.704-1(b)(2)(ii)(d)(6), items of Partnership income and gain shall be specially allocated to such Partner in an amount and manner sufficient to eliminate, to the extent required by the Treasury Regulations promulgated under Section 704(b) of the Code, the deficit balance, if any, in its Adjusted Capital Account created by such adjustments, allocations or distributions as quickly as possible unless such deficit balance is otherwise eliminated pursuant to Section 6.1(d)(i) or (ii).

(v) *Gross Income Allocations*. In the event any Partner has a deficit balance in its Capital Account at the end of any Partnership taxable period in excess of the sum of (A) the amount such Partner is obligated to restore pursuant to the provisions of this Agreement and (B) the amount such Partner is deemed obligated to restore pursuant to Treasury Regulation Sections 1.704-2(g) and 1.704-2(i)(5), such Partner shall be specially allocated items of Partnership gross income, gain and Simulated Gain in the amount of such excess as quickly as possible; *provided* that an allocation pursuant to this Section 6.1(d)(v) shall be made only if and to the extent that such Partner would have a deficit balance in its Capital Account as adjusted after all other allocations provided for in this Section 6.1 have been tentatively made as if this Section 6.1(d)(v) were not in this Agreement.

(vi) *Nonrecourse Deductions*. Nonrecourse Deductions for any taxable period shall be allocated to the Partners in accordance with their respective Percentage Interests. If the General Partner determines that the Partnership's Nonrecourse Deductions should be allocated in a different ratio to satisfy the safe harbor requirements of the Treasury Regulations promulgated under Section 704(b) of the Code, the General Partner is authorized, upon notice to the other Partners, to revise the prescribed ratio to the numerically closest ratio that does satisfy such requirements.

(vii) *Partner Nonrecourse Deductions*. Partner Nonrecourse Deductions for any taxable period shall be allocated 100% to the Partner that bears the Economic Risk of Loss with respect to the Partner Nonrecourse Debt to which such Partner Nonrecourse Deductions are attributable in accordance with Treasury Regulation Section 1.704-2(i)(1). If more than one Partner bears the Economic Risk of Loss with respect to a Partner Nonrecourse Debt, such Partner Nonrecourse Deductions attributable thereto shall be allocated between or among such Partners in accordance with the ratios in which they share such Economic Risk of Loss.

(viii) *Nonrecourse Liabilities*. For purposes of Treasury Regulation Section 1.752-3(a)(3), the Partners agree that Nonrecourse Liabilities of the Partnership in excess of the sum of (A) the amount of Partnership Minimum Gain and (B) the total amount of Nonrecourse Built-in Gain shall be allocated among the Partners in accordance with their respective Percentage Interests.

(ix) *Code Section 754 Adjustments*. To the extent an adjustment to the adjusted tax basis of any Partnership asset pursuant to Section 734(b) or 743(b) of the Code is required, pursuant to Treasury Regulation Section 1.704-1(b)(2)(iv)(m), to be taken into account in determining Capital Accounts, the amount of such adjustment to the Capital Accounts shall be treated as an item of gain or Simulated Gain (if the adjustment increases the basis of the asset) or loss or Simulated Loss (if the adjustment decreases such basis), and such item of gain or loss, Simulated Gain or Simulated Loss shall be specially allocated to the Partners in a manner consistent with the manner in which their Capital Accounts are required to be adjusted pursuant to such Section of the Treasury Regulations.

(x) *Economic Uniformity*.

(A) With respect to an event triggering an adjustment to the Carrying Value of Partnership property pursuant to Section 5.4(d) during any taxable period of the Partnership ending upon, or after, the issuance of IDR Reset Common Units pursuant to Section 5.9, any Unrealized Gains and Unrealized Losses shall be allocated among the Partners in a manner that to the nearest extent possible results in the Capital Accounts maintained with respect to such IDR Reset Common Units issued pursuant to Section 5.9 equaling the product of (x) the Aggregate Quantity of IDR Reset Common Units and (y) the Per Unit Capital Amount for an Initial Common Unit.

(B) With respect to any taxable period during which an IDR Reset Common Unit is transferred to any Person who is not an Affiliate of the transferor, all or a portion of the remaining items of Partnership gross income or gain for such taxable period shall be allocated 100% to the transferor Partner of such transferred IDR Reset Common Unit until such transferor Partner has been allocated an amount of gross income or gain that increases the Capital Account maintained with respect to such transferred IDR Reset Common Unit to an amount equal to the Per Unit Capital Amount for an Initial Common Unit.

(xi) *Curative Allocation*.

(A) Notwithstanding any other provision of this Section 6.1, other than the Required Allocations, the Required Allocations shall be taken into account in making the Agreed Allocations so that, to the extent possible, the net amount of items of income, gain, loss, deduction, Simulated Depletion, Simulated Gain and Simulated Loss allocated to each Partner pursuant to the Required Allocations and the Agreed Allocations, together, shall be equal to the net amount of such items that would have been allocated to each such Partner under the Agreed Allocations had the Required Allocations and the related Curative Allocation not otherwise been provided in this Section 6.1. Notwithstanding the preceding sentence, Required Allocations relating to (1) Nonrecourse Deductions shall not be taken into account except to the extent that there has been a decrease in Partnership Minimum Gain and (2) Partner Nonrecourse Deductions shall not be taken into account except to the extent that there has been a decrease in Partner Nonrecourse Debt Minimum Gain. Allocations pursuant to this Section 6.1(d)(xi)(A) shall only be made with respect to Required Allocations to the extent the General Partner determines that such allocations will otherwise be inconsistent with the economic agreement among the Partners. Further, allocations pursuant to this Section 6.1(d)(xi)(A) shall be deferred with respect to allocations pursuant to clauses (1) and (2) hereof to the extent the General Partner determines that such allocations are likely to be offset by subsequent Required Allocations.

(B) The General Partner shall, with respect to each taxable period, (1) apply the provisions of Section 6.1(d)(xi)(A) in whatever order is most likely to minimize the economic distortions that might otherwise result from the Required Allocations, and (2) divide all allocations pursuant to Section 6.1(d)(xi)(A) among the Partners in a manner that is likely to minimize such economic distortions.

(xii) *Corrective Allocations*. In the event of any allocation of Additional Book Basis Derivative Items or any Book-Down Event or any recognition of a Net Termination Loss, the following rules shall apply:

(A) In the case of any allocation of Additional Book Basis Derivative Items (other than an allocation of Unrealized Gain or Unrealized Loss under Section 5.4(d) hereof), the General Partner shall allocate additional items of gross income and gain away from the holders of Incentive Distribution Rights to the Unitholders, or additional items of deduction and loss away from the Unitholders to the holders of Incentive Distribution Rights, to the extent that the Additional Book Basis Derivative Items allocated to the Unitholders exceed their Share of Additional Book Basis Derivative Items. For this purpose, the Unitholders shall be treated as being allocated Additional Book Basis Derivative Items to the extent that such Additional Book Basis Derivative Items have reduced the amount of income that would otherwise have been allocated to the Unitholders under this Agreement (e.g., Additional Book Basis Derivative Items taken into account in computing cost of goods sold would reduce the amount of book income otherwise available for allocation among the Partners). Any allocation made pursuant to this Section 6.1(d)(xii)(A) shall be made after all of the other Agreed Allocations have been made as if this Section 6.1(d)(xii) were not in this Agreement and, to the extent necessary, shall require the reallocation of items that have been allocated pursuant to such other Agreed Allocations.

(B) In the case of any negative adjustments to the Capital Accounts of the Partners resulting from a Book-Down Event or from the recognition of a Net Termination Loss, such negative adjustment (1) shall first be allocated, to the extent of the Aggregate Remaining Net Positive Adjustments, in such a manner, as determined by the General Partner, that to the extent possible the aggregate Capital Accounts of the Partners will equal the amount that would have been the Capital Account balance of the Partners if no prior Book-Up Events had occurred, and (2) any negative adjustment in excess of the Aggregate Remaining Net Positive Adjustments shall be allocated pursuant to Section 6.1(c) hereof.

(C) In making the allocations required under this Section 6.1(d)(xii), the General Partner may apply whatever conventions or other methodology it determines will satisfy the purpose of this Section 6.1(d)(xii).

(e) *Simulated Depletion and Simulated Loss*.

(i) In accordance with Treasury Regulation Section 1.704-1(b)(2)(iv)(k), Simulated Depletion with respect to each oil and gas property shall be allocated among the General Partner and the Unitholders Pro Rata.

(ii) Simulated Loss with respect to the disposition of an oil and gas property shall be allocated among the Partners in proportion to their allocable share of total amount realized from such disposition under Section 6.2(c)(i).

SECTION 6.2. *Allocations for Tax Purposes*.

(a) Except as otherwise provided herein, for U.S. federal income tax purposes, each item of income, gain, loss and deduction shall be allocated among the Partners in the same manner as its correlative item of "book" income, gain, loss or deduction is allocated pursuant to Section 6.1.

(b) The deduction for depletion with respect to each separate oil and gas property (as defined in Section 614 of the Code) shall be computed for U.S. federal income tax purposes separately by the Partners rather than by the Partnership in accordance with Section 613A(c)(7)(D) of the Code. Except as provided in Section 6.2(c)(iii), for purposes of such computation (before taking into account any adjustments resulting from an election made by the Partnership under Section 754 of the Code), the adjusted tax basis of each oil and gas property (as defined in Section 614 of the Code) shall be allocated among the Partners Pro Rata. Each Partner shall separately keep records of his share of the adjusted tax basis in each oil and gas property, allocated as provided above, adjust such share of the adjusted tax basis for any cost or percentage depletion allowable with respect to such property, and use such adjusted tax basis in the computation of its cost depletion or in the computation of his gain or loss on the disposition of such property by the Partnership.

(c) Except as provided in Section 6.2(c)(iii), for the purposes of the separate computation of gain or loss by each Partner on the sale or disposition of each separate oil and gas property (as defined in Section 614 of the Code), the Partnership's allocable share of the "amount realized" (as such term is defined in Section 1001(b) of the Code) from such sale or disposition shall be allocated for U.S. federal income tax purposes among the Partners as follows:

(i) first, to the extent such amount realized constitutes a recovery of the Simulated Basis of the property, to the Partners in the same proportion as the depletable basis of such property was allocated to the Partners pursuant to Section 6.2(b) (without regard to any special allocation of basis under Section 6.2(c)(iii)).

(ii) second, the remainder of such amount realized, if any, to the Partners so that, to the maximum extent possible, the amount realized allocated to each Partner under this Section 6.2(c)(ii) will equal such Partner's share of the Simulated Gain recognized by the Partnership from such sale or disposition.

(iii) The Partners recognize that with respect to Contributed Property and Adjusted Property there will be a difference between the Carrying Value of such property at the time of contribution or revaluation, as the case may be, and the adjusted tax basis of such property at that time. All items of tax depreciation, cost recovery, amortization, adjusted tax basis of depletable properties, amount realized and gain or loss with respect to such Contributed Property and Adjusted Property shall be allocated among the Partners to take into account the disparities between the Carrying Values and the adjusted tax basis with respect to such properties in accordance with the principles of Treasury Regulation Section 1.704-3(d).

(d) In an attempt to eliminate Book-Tax Disparities attributable to a Contributed Property or Adjusted Property other than an oil and gas property pursuant to Section 6.2(c), items of income, gain, loss, depreciation, amortization and cost recovery deductions shall be allocated for U.S. federal income tax purposes among the Partners as follows:

(i) (A) In the case of a Contributed Property, such items attributable thereto shall be allocated among the Partners in the manner provided under Section 704(c) of the Code that takes into account the variation between the Agreed Value of such property and its adjusted basis at the time of contribution; and (B) any item of Residual Gain or Residual Loss attributable to a Contributed Property shall be allocated among the Partners in the same manner as its correlative item of "book" gain or loss is allocated pursuant to Section 6.1.

(ii) (A) In the case of an Adjusted Property, such items shall (1) first, be allocated among the Partners in a manner consistent with the principles of Section 704(c) of the Code to take into account the Unrealized Gain or Unrealized Loss attributable to such property and the allocations thereof pursuant to Section 5.4(d)(i) or 5.4(d)(ii), and (2) second, in the event such property was originally a Contributed Property, be allocated among the Partners in a manner consistent with Section 6.2(b)(i)(A); and (B) any item of Residual Gain or Residual Loss attributable to an Adjusted Property shall be allocated among the Partners in the same manner as its correlative item of "book" gain or loss is allocated pursuant to Section 6.1.

(iii) The General Partner shall apply the principles of Treasury Regulation Section 1.704-3(d) to eliminate Book-Tax Disparities.

(e) For the proper administration of the Partnership and for the preservation of uniformity of the Limited Partner Interests (or any class or classes thereof), the General Partner shall (i) adopt such conventions as it deems appropriate in determining the amount of depreciation, amortization and cost recovery deductions; (ii) make special allocations for U.S. federal income tax purposes of income (including gross income) or deductions; and (iii) amend the provisions of this Agreement as appropriate (A) to reflect the proposal or promulgation of Treasury Regulations under Section 704(b) or Section 704(c) of the Code or (B) otherwise to preserve or achieve uniformity of the Limited Partner Interests (or any class or classes thereof). The General Partner may adopt such conventions, make such allocations and make such amendments to this Agreement as provided in this Section 6.2(c) only if such conventions, allocations or amendments would not have a material adverse effect on the Partners, the holders of any class or classes of Limited Partner Interests issued and Outstanding or the Partnership, and if such allocations are consistent with the principles of Section 704 of the Code.

(f) The General Partner may determine to depreciate or amortize the portion of an adjustment under Section 743(b) of the Code attributable to unrealized appreciation in any Adjusted Property (to the extent of the unamortized Book-Tax Disparity) using a predetermined rate derived from the depreciation or amortization method and useful life applied to the Partnership's common basis of such property, despite any inconsistency of such approach with Treasury Regulation Section 1.167(c)-1(a)(6), Treasury Regulation Section 1.197-2(g)(3), or any successor regulations thereto. If the General Partner determines that such reporting position cannot reasonably be taken, the General Partner may adopt depreciation and amortization conventions under which all purchasers acquiring Limited Partner Interests in the same month would receive depreciation and amortization deductions, based upon the same applicable rate as if they had purchased a direct interest in the Partnership's property. If the General Partner chooses not to utilize such aggregate method, the General Partner may use any other depreciation and amortization conventions to preserve the uniformity of the intrinsic tax characteristics of any Limited Partner Interests, so long as such conventions would not have a material adverse effect on the Limited Partners or the Record Holders of any class or classes of Limited Partner Interests.

(g) In accordance with Treasury Regulation Sections 1.1245-1(e) and 1.1250-1(f), any gain allocated to the Partners upon the sale or other taxable disposition of any Partnership asset shall, to the extent possible, after taking into account other required allocations of gain pursuant to this Section 6.2, be characterized as Recapture Income in the same proportions and to the same extent as such Partners (or their predecessors in interest) have been allocated any deductions directly or indirectly giving rise to the treatment of such gains as Recapture Income.

(h) All items of income, gain, loss, deduction and credit recognized by the Partnership for U.S. federal income tax purposes and allocated to the Partners in accordance with the provisions hereof shall be determined without regard to any election under Section 754 of the Code which may be made by the Partnership; *provided*, *however*, that such allocations, once made, shall be adjusted (in the manner determined by the General Partner) to take into account those adjustments permitted or required by Sections 734 and 743 of the Code.

(i) Each item of Partnership income, gain, loss and deduction shall, for U.S. federal income tax purposes, be determined on an annual basis and prorated on a monthly basis and shall be allocated to the Partners as of the opening of the National Securities Exchange on which the Partnership Interests are listed or admitted for trading on the first Business Day of each month; *provided*, *however*, that gain or loss on a sale or other disposition of any assets of the Partnership or any other extraordinary item of income or loss realized and recognized other than in the ordinary course of business, as determined by the General Partner in its sole discretion, shall be allocated to the Partners as of the opening of the National Securities Exchange on which the Partnership Interests are listed or admitted for trading on the first Business Day of the month in which such gain or loss is recognized for U.S. federal income tax purposes. The General Partner may revise, alter or otherwise modify such methods of allocation to the extent permitted or required by Section 706 of the Code and the regulations or rulings promulgated thereunder.

(j) Allocations that would otherwise be made to a Limited Partner under the provisions of this Article VI shall instead be made to the beneficial owner of Limited Partner Interests held by a nominee in any case in which the nominee has furnished the identity of such owner to the Partnership in accordance with Section 6031(c) of the Code or any other method determined by the General Partner.

SECTION 6.3. *Requirement and Characterization of Distributions; Distributions to Record Holders*.

(a) Except as described in Section 6.3(b), within 45 days following the end of each Quarter (or if such 45th day is not a Business Day, then the Business Day immediately following such 45th day) commencing with the Quarter ending on March 31, 2012, an amount equal to 100% of Available Cash with respect to such Quarter shall, subject to Section 17-607 of the Delaware Act, be distributed in accordance with this Article VI by the Partnership to the Partners as of the Record Date selected by the General Partner. All amounts of Available Cash distributed by the Partnership on any date from any source shall be deemed to be Operating Surplus until the sum of all amounts of Available Cash theretofore distributed by the Partnership to the Partners pursuant to Section 6.4 equals the Operating Surplus from the Closing Date through the close of the immediately preceding Quarter. Any remaining amounts of Available Cash distributed by the Partnership on such date shall, except as otherwise provided in Section 6.5, be deemed to be "*Capital Surplus*." All distributions required to be made under this Agreement shall be made subject to Section 17-607 of the Delaware Act.

(b) Notwithstanding Section 6.3(a), in the event of the dissolution and liquidation of the Partnership, all cash received during or after the Quarter in which the Liquidation Date occurs, other than from borrowings described in (a)(ii) of the definition of Available Cash, shall be applied and distributed solely in accordance with, and subject to the terms and conditions of, Section 12.4.

(c) The General Partner may treat taxes paid by the Partnership on behalf of, or amounts withheld with respect to, all or less than all of the Partners, as a distribution of Available Cash to such Partners, as determined by the General Partner.

(d) Each distribution in respect of a Partnership Interest shall be paid by the Partnership, directly or through the Transfer Agent or through any other Person or agent, only to the Record Holder of such Partnership Interest as of the Record Date set for such distribution. Such payment shall constitute full payment and satisfaction of the Partnership's liability in respect of such payment, regardless of any claim of any Person who may have an interest in such payment by reason of an assignment or otherwise.

SECTION 6.4. *Distributions of Available Cash from Operating Surplus*.

(a) Available Cash with respect to any Quarter that is deemed to be Operating Surplus pursuant to the provisions of Section 6.3 or 6.5 shall, subject to Section 17-607 of the Delaware Act, be distributed as follows, except as otherwise required by Section 5.5(b) in respect of additional Partnership Interests issued pursuant thereto:

(i) First, (A) 2% to the holders of Class A Units, Pro Rata, and (B) 98% to the holders of Common Units, Pro Rata, until there has been distributed in respect of each Class A Unit then Outstanding and each Common Unit then Outstanding an amount equal to the Minimum Quarterly Distribution for such Quarter;

(ii) Second, (A) 2% to the holders of Class A Units, Pro Rata, and (B) 98% to the holders of Common Units, Pro Rata, until there has been distributed in respect of each Class A Unit then Outstanding and each Common Unit then Outstanding an amount equal to the First Target Distribution for such Quarter;

(iii) Third, (A) 2% to the holders of Class A Units, Pro Rata, (B) 85% to the holders of Common Units, Pro Rata, and (C) 13% to the holders of the Incentive Distribution Rights, Pro Rata, until there has been distributed in respect of each Class A Unit then Outstanding and each Common Unit then Outstanding an amount equal to the Second Target Distribution for such Quarter; and

(iv) Fourth, (A) 2% to the holders of Class A Units, Pro Rata, (B) 75% to the holders of Common Units, Pro Rata, and (C) 23% to the holders of the Incentive Distribution Rights, Pro Rata, until there has been distributed in respect of each Class A Unit then Outstanding and each Common Unit then Outstanding an amount equal to the Third Target Distribution for such Quarter; and

(v) Thereafter, (A) 2% to the holders of Class A Units, Pro Rata, (B) 50% to the holders of Common Units, Pro Rata, and 48% to the holders of the Incentive Distribution Rights, Pro Rata.

provided, *however*, if the Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution and Third Target Distribution have been reduced to zero pursuant to the second sentence of Section 6.6(a), the distribution of Available Cash that is deemed to be Operating Surplus with respect to any Quarter will be made solely in accordance with Section 6.4(a)(v).

SECTION 6.5. *Distributions of Available Cash from Capital Surplus*.

Available Cash that is deemed to be Capital Surplus pursuant to the provisions of Section 6.3(a) shall, subject to Section 17-607 of the Delaware Act, be distributed, unless the provisions of Section 6.3 require otherwise, as follows:

(a) First, 2% to the holders of Class A Units, Pro Rata, and 98% to the holders of Common Units, Pro Rata, until a hypothetical holder of a Common Unit acquired on the Closing Date has received with respect to such Common Unit, during the period since the Closing Date through such date, distributions of Available Cash that are deemed to be Capital Surplus in an aggregate amount equal to the Initial Unit Price; and

(b) Second, any remaining Available Cash shall be distributed as if it were Operating Surplus and shall be distributed in accordance with Section 6.4.

SECTION 6.6. *Adjustment of Minimum Quarterly Distribution and Target Distribution Levels*.

(a) The Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution and Third Target Distribution shall be proportionately adjusted in the event of any distribution, combination or subdivision (whether effected by a distribution payable in Partnership Interests or otherwise) of Units or other Partnership Interests in accordance with Section 5.7. In the event of a distribution of Available Cash that is deemed to be from Capital Surplus, the then-applicable Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution and Third Target Distribution shall be adjusted proportionately downward to equal the product obtained by multiplying the otherwise applicable Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution or Third Target Distribution, as the case may be, by a fraction, the numerator of which is the Unrecovered Capital of the Common Units immediately after giving effect to such distribution and the denominator of which is the Unrecovered Capital of the Common Units immediately prior to giving effect to such distribution.

(b) The Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution and Third Target Distribution shall also be subject to adjustment pursuant to Section 5.9 and Section 6.8.

SECTION 6.7. *Special Provisions Relating to the Holders of Incentive Distribution Rights*.

Notwithstanding anything to the contrary set forth in this Agreement, the holders of the Incentive Distribution Rights (a) shall (i) possess the rights and obligations provided in this Agreement with respect to a Limited Partner pursuant to Articles III and VII and (ii) have a Capital Account as a Partner pursuant to Section 5.4 and all other provisions related thereto and (b) shall not (i) be entitled to vote on any matters requiring the approval or vote of the holders of Outstanding Units, except as required by law, (ii) be entitled to any distributions from the Partnership other than as provided in Section 6.4(a) and Section 12.4 or (iii) be allocated items of income, gain, loss or deduction other than as specified in this Article VI.

SECTION 6.8. *Entity-Level Taxation*.

If legislation is enacted or the interpretation of existing legislation is modified by a governmental authority, which, after giving effect to such enactment or modification, results in any Group Member becoming subject to federal, state, or local or non-U.S. income or withholding taxes in excess of the amount of such taxes due from any Group Member prior to such enactment or modification (including any increase in the rate of such taxation applicable to such Group Member), then the General Partner may, at its option, reduce the Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution and Third Target Distribution by the amount of income or withholding taxes that are payable by reason of any such new legislation or interpretation (the "*Incremental Income Taxes*"), or any portion thereof selected by the General Partner, in the manner provided in this Section 6.8. If the General Partner elects to reduce the Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution or Third Target Distribution for any Quarter with respect to all or a portion of any Incremental Income Taxes, the General Partner shall estimate for such Quarter the Partnership Group's aggregate liability (the "*Estimated Incremental Quarterly Tax Amount*") for all (or the relevant portion of) such Incremental Income Taxes; *provided* that any difference between such estimate and the actual liability for Incremental Income Taxes (or the relevant portion thereof) for such Quarter may, to the extent determined by the General Partner, be taken into account in determining the Estimated Incremental Quarterly Tax Amount with respect to each Quarter in which any such difference can be determined. For each such Quarter, the Minimum Quarterly Distribution, First Target Distribution, Second Target Distribution and Third Target Distribution, shall be adjusted to equal the product obtained by multiplying (a) the amounts therefor that are set out herein prior to the application of this Section 6.8 times (b) the quotient obtained by dividing (i) Available Cash with respect to such Quarter by (ii) the sum of Available Cash with respect to such Quarter and the Estimated Incremental Quarterly Tax Amount for such Quarter, as determined by the General Partner. For purposes of the foregoing, Available Cash with respect to a Quarter will be deemed reduced by the Estimated Incremental Quarterly Tax Amount for that Quarter.

ARTICLE VII

MANAGEMENT AND OPERATION OF BUSINESS

SECTION 7.1. *Management*.

(a) The General Partner shall conduct, direct and manage all activities of the Partnership. Except as otherwise expressly provided in this Agreement, but without limitation on the ability of the General Partner to delegate its rights and powers to other Persons, all management powers over the business and affairs of the Partnership shall be exclusively vested in the General Partner, and no Limited Partner shall have any management power over the business and affairs of the Partnership. In addition to the powers now or hereafter granted to a general partner of a limited partnership under applicable law or that are granted to the General Partner under any other provision of this Agreement, the General Partner shall, subject to Section 7.4 and the other terms set forth in this Agreement, have full power and authority to do all things and on such terms as it determines to be necessary or appropriate to conduct the business of the Partnership, to exercise all powers set forth in Section 2.5 and to effectuate the purposes set forth in Section 2.4, including the following:

(i) the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of, or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible or exchangeable into Partnership Interests, and the incurring of any other obligations;

(ii) the making of tax, regulatory and other filings, or rendering of periodic or other reports to governmental or other agencies having jurisdiction over the business or assets of the Partnership;

(iii) the acquisition, disposition, mortgage, pledge, encumbrance, hypothecation or exchange of any or all of the assets of the Partnership or the merger or other combination of the Partnership with or into another Person;

(iv) the use of the assets of the Partnership (including cash on hand) for any purpose consistent with the terms of this Agreement, including the financing of the conduct of operations, including operations of any Group Member; subject to Section 7.7(a), the lending of funds to other Persons (including other Group Members); the repayment or guarantee of obligations and the making of capital contributions;

(v) the negotiation, execution and performance of any contracts, conveyances or other instruments (including instruments that limit the liability of the Partnership under contractual arrangements to all or particular assets of the Partnership, with the other party to the contract to have no recourse against the General Partner or its assets other than its interest in the Partnership, even if the same results in the terms of the transaction being less favorable to the Partnership than would otherwise be the case);

(vi) the distribution of Partnership cash;

(vii) the selection, employment, retention and dismissal of employees (including employees having titles such as "president," "vice president," "secretary" and "treasurer") and agents, internal and outside attorneys, accountants, consultants and contractors of the General Partner or any Group Member and the determination of their compensation and other terms of employment or hiring;

(viii) the maintenance of insurance for the benefit of the Partnership Group, the Partners and the Indemnitees;

(ix) the formation of, or acquisition of an interest in, and the contribution of property and the making of loans to, any further limited or general partnerships, joint ventures, corporations, limited liability companies or other Persons (including the acquisition of interests in, and the contributions of property to, any Group Member from time to time);

(x) the control of any matters affecting the rights and obligations of the Partnership, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expenses and the settlement of claims and litigation;

(xi) the indemnification of any Person against liabilities and contingencies to the extent permitted by law;

(xii) the entering into of listing agreements with any National Securities Exchange and the delisting of some or all of the Limited Partner Interests from, or requesting that trading be suspended on, any such National Securities Exchange;

(xiii) the purchase, sale or other acquisition or disposition of Partnership Interests, or the issuance of options, rights, warrants, appreciation rights and tracking and phantom interests relating to Partnership Interests;

(xiv) the undertaking of any action in connection with the Partnership's participation in any Group Member;

(xv) the entering into of agreements with any of its Affiliates to render services to a Group Member or to itself in the discharge of its duties as General Partner of the Partnership; and

(xvi) the registering for resale under the Securities Act and applicable state securities laws of any Partnership Interests held or hereafter acquired by the General Partner or any Affiliate of the General Partner.

(b) Notwithstanding any other provision of this Agreement, the Delaware Act or any applicable law, rule or regulation, each of the Partners and each other Person who may acquire an interest in Partnership Interests or is otherwise bound by this Agreement hereby (i) approves, ratifies and confirms the execution, delivery and performance by the parties thereto of this Agreement and the Separation Agreement and the other agreements described in or filed as exhibits to the Registration Statement that are related to the transactions contemplated by the Registration Statement; (ii) agrees that the General Partner (on its own or on behalf of the Partnership) is authorized to execute, deliver and perform the agreements referred to in clause (i) of this sentence and the other agreements, acts, transactions and matters described in or contemplated by the Registration Statement on behalf of the Partnership without any further act, approval or vote of the Partners or the other Persons who may acquire an interest in Partnership Interests or is otherwise bound by this Agreement; and (iii) agrees that the execution, delivery or performance by the General Partner, any Group Member or any Affiliate of any of them, of this Agreement or any agreement authorized or permitted under this Agreement (including the exercise by the

General Partner or any Affiliate of the General Partner of the rights accorded pursuant to Article XV), shall not constitute a breach by the General Partner of any duty that the General Partner may owe the Partnership or the Limited Partners or any other Persons under this Agreement (or any other agreements) or of any duty existing at law, in equity or otherwise.

SECTION 7.2. *Duties*.

Except as expressly set forth in this Agreement or the Delaware Act, neither the General Partner nor any other Indemnitee shall have any duties or liabilities, including fiduciary duties, to the Partnership, any Group Member or any Limited Partner, and the Partners agree that the provisions of this Agreement, to the extent that they restrict, eliminate or otherwise modify the duties and liabilities, including fiduciary duties, of the General Partner or any other Indemnitee otherwise existing at law or in equity, replace such other duties and liabilities of the General Partner or such other Indemnitee. The Limited Partners and any other Person who acquires an interest in a Partnership Interest or any other Person who is bound by this Agreement shall be deemed to have expressly approved this Section 7.2.

SECTION 7.3. *Certificate of Limited Partnership*.

The General Partner has caused the Certificate of Limited Partnership to be filed with the Secretary of State of the State of Delaware as required by the Delaware Act. The General Partner shall use all reasonable efforts to cause to be filed such other certificates or documents that the General Partner determines to be necessary or appropriate for the formation, continuation, qualification and operation of a limited partnership (or a partnership in which the limited partners have limited liability) in the State of Delaware or any other state in which the Partnership may elect to do business or own property. To the extent the General Partner determines such action to be necessary or appropriate, the General Partner shall file amendments to and restatements of the Certificate of Limited Partnership and do all things to maintain the Partnership as a limited partnership (or a partnership or other entity in which the limited partners have limited liability) under the laws of the State of Delaware or of any other state in which the Partnership may elect to do business or own property. Subject to the terms of Section 3.4(a), the General Partner shall not be required, before or after filing, to deliver or mail a copy of the Certificate of Limited Partnership, any qualification document or any amendment thereto to any Limited Partner.

SECTION 7.4. *Restrictions on the General Partner's Authority*.

Except as provided in Articles XII and XIV, the General Partner may not sell, exchange or otherwise dispose of all or substantially all of the assets of the Partnership Group, taken as a whole, in a single transaction or a series of related transactions, to a Person who is not a member of the Partnership Group, without the approval of the holders of a Unit Majority; *provided*, *however*, that this provision shall not preclude or limit the General Partner's ability to mortgage, pledge, hypothecate or grant a security interest in all or substantially all of the assets of the Partnership Group and shall not apply to any forced sale of any or all of the assets of the Partnership Group pursuant to the foreclosure of, or other realization upon, any such encumbrance.

SECTION 7.5. *Reimbursement of the General Partner*.

(a) Except as provided in this Section 7.5 and elsewhere in this Agreement, the General Partner shall not be compensated for its services as a general partner or managing member of any Group Member.

(b) The General Partner shall be reimbursed from the Partnership or the Partnership Group on a monthly basis, or such other basis as the General Partner may determine, for (i) all direct and indirect expenses it incurs or payments it makes on behalf of the Partnership Group (including salary, bonus, incentive compensation, employee benefits and other amounts paid to any Person, including Affiliates of the General Partner, to perform services for the Partnership Group or for the General Partner in the discharge of its duties to the Partnership

Group) and (ii) all other expenses allocable to the Partnership Group or otherwise incurred by the General Partner in connection with managing and operating the Partnership Group's business and affairs (including expenses allocated to the General Partner by its Affiliates). The General Partner shall determine the expenses that are allocable to the Partnership Group. Reimbursements pursuant to this Section 7.5 shall be in addition to any reimbursement to the General Partner as a result of indemnification pursuant to Section 7.8.

(c) The General Partner, without the approval of the Limited Partners (who shall have no right to vote in respect thereof), may propose and adopt on behalf of the Partnership benefit plans, programs and practices (including plans, programs and practices involving the issuance of Partnership Interests or options to purchase or rights, warrants or appreciation rights or phantom or tracking interests relating to Partnership Interests), or cause the Partnership to issue Partnership Interests in connection with, or pursuant to, any benefit plan, program or practice maintained or sponsored by the General Partner or any of its Affiliates, in each case for the benefit of employees and directors of the General Partner or any of its Affiliates, in respect of services performed, directly or indirectly, for the benefit of the Partnership Group. The Partnership agrees to issue and sell to the General Partner or any of its Affiliates any Partnership Interests that the General Partner or such Affiliate is obligated to provide to any employees and directors pursuant to any such benefit plans, programs or practices. Expenses incurred by the General Partner in connection with any such plans, programs and practices (including the net cost to the General Partner or such Affiliate of Partnership Interests purchased by the General Partner or such Affiliate from the Partnership or otherwise, to fulfill options or awards under such plans, programs and practices) shall be reimbursed in accordance with Section 7.5(b). Any and all obligations of the General Partner under any benefit plans, programs or practices adopted by the General Partner as permitted by this Section 7.5(c) shall constitute obligations of the General Partner hereunder and shall be assumed by any successor General Partner approved pursuant to Section 11.1 or Section 11.2 or the transferee of or successor to all of the General Partner's General Partner Interest (represented by Class A Units).

(d) The General Partner and its Affiliates may charge any member of the Partnership Group a management fee to the extent necessary to allow the Partnership Group to reduce the amount of any state franchise or income tax or any tax based upon the revenues or gross margin of any member of the Partnership Group if the tax benefit produced by the payment of such management fee or fees exceeds the amount of such fee or fees.

SECTION 7.6. *Outside Activities*.

(a) The General Partner, for so long as it is the General Partner of the Partnership, (i) agrees that its sole business will be to act as a general partner or managing member, as the case may be, of the Partnership and any other partnership or limited liability company of which the Partnership is, directly or indirectly, a partner or member and to undertake activities that are ancillary or related thereto (including being a Limited Partner in the Partnership) and (ii) shall not engage in any business or activity or incur any debts or liabilities except in connection with or incidental to (A) its performance as general partner or managing member, if any, of one or more Group Members or as described in or contemplated by the Registration Statement, (B) the acquiring, owning or disposing of debt securities or equity interests in any Group Member or (C) the guarantee of, and mortgage, pledge, or encumbrance of any or all of its assets in connection with, any indebtedness of any Affiliate of the General Partner. It is expressly understood that the restrictions set forth in this Section 7.6(a) shall not apply to any Person (including any Unrestricted Person) other than the General Partner.

(b) Each Unrestricted Person (other than the General Partner) shall have the right to engage in businesses of every type and description and other activities for profit and to engage in and possess an interest in other business ventures of any and every type or description, whether in businesses engaged in or anticipated to be engaged in by any Group Member, independently or with others, including business interests and activities in direct competition with the business and activities of any Group Member. No such business interest or activity shall constitute a breach of this Agreement or any duty otherwise existing at law, in equity or otherwise or obligation of any type whatsoever, to the Partnership, any Group Member, any Partner, any Person who acquires an interest in a Partnership Interest or other person who is bound by this Agreement. None of any Group Member, any Limited Partner or any other Person shall have any rights by virtue of this Agreement or the partnership relationship established hereby in any business ventures of any Unrestricted Person.

(c) Notwithstanding anything to the contrary in this Agreement, (i) the engaging in competitive activities by any Unrestricted Person (other than the General Partner) in accordance with the provisions of this Section 7.6 is hereby approved by the Partnership and all Partners, (ii) it shall be deemed not to be a breach by the General Partner or any other Unrestricted Persons of this Agreement or any duty otherwise existing at law, in equity or otherwise or obligation of any type whatsoever, to the Partnership, any Group Member, any Partner, any Person who acquires an interest in a Partnership Interest or other person who is bound by this Agreement for the Unrestricted Persons (other than the General Partner) to engage in such business interests and activities in preference to or to the exclusion of the Partnership or any other Group Member and (iii) the Unrestricted Persons (including the General Partner) shall have no obligation hereunder or as a result of any duty otherwise existing at law, in equity or otherwise or obligation of any type whatsoever, to present business opportunities to the Partnership or any other Group Member. Notwithstanding anything to the contrary in this Agreement, the doctrine of corporate opportunity, or any analogous doctrine, shall not apply to any Unrestricted Person (including the General Partner). No Unrestricted Person (including the General Partner) who acquires knowledge of a potential transaction, agreement, arrangement or other matter that may be an opportunity for the Partnership, shall have any duty to communicate or offer such opportunity to the Partnership, and such Unrestricted Person (including the General Partner) shall not be liable to the Partnership, any Group Member, any Partner, any Person who acquires an interest in a Partnership Interest or other person who is bound by this Agreement for breach of this Agreement or any duty otherwise existing at law, in equity or otherwise or obligation of any type whatsoever, by reason of the fact that such Unrestricted Person (including the General Partner) pursues or acquires for itself, directs such opportunity to another Person or does not communicate such opportunity or information to the Partnership.

(d) The General Partner and each of its Affiliates may acquire Units or other Partnership Interests in addition to those acquired on or prior to the Closing Date and, except as otherwise provided in this Agreement, shall be entitled to exercise, at their option, all rights relating to all Units and/or other Partnership Interests acquired by them. The term “Affiliates” when used in this Section 7.6(d) with respect to the General Partner shall not include any Group Member.

(e) Notwithstanding anything to the contrary in this Agreement, to the extent that any provision of this Agreement purports or is interpreted to have the effect of restricting, modifying or eliminating any duty that might otherwise, as a result of the law of the State of Delaware or any other applicable law, be owed by the General Partner to the Partnership, any Group Member, any Partner, any Person who acquires an interest in a Partnership Interest or other person who is bound by this Agreement, or to constitute a waiver or consent by the Partnership, any Group Member, any Partner, any Person who acquires an interest in a Partnership Interest or other person who is bound by this Agreement, then in each case such provisions shall be deemed to have been approved by such Persons.

SECTION 7.7. *Loans from the General Partner; Loans or Contributions from the Partnership or Group Members.*

(a) The General Partner or any of its Affiliates may, but shall be under no obligation to, lend to any Group Member, and any Group Member may borrow from the General Partner or any of its Affiliates, funds needed or desired by the Group Member for such periods of time and in such amounts as the General Partner may determine. The borrowing party shall reimburse the lending party for any costs (other than any additional interest costs) incurred by the lending party in connection with the borrowing of such funds. For purposes of this Section 7.7(a), the term “Group Member” shall include any Affiliate of a Group Member that is controlled by the Group Member.

(b) The Partnership may lend or contribute to any Group Member, and any Group Member may borrow from the Partnership, funds on terms and conditions determined by the General Partner.

(c) No borrowing by any Group Member or the approval thereof by the General Partner shall be deemed to constitute a breach of any duty hereunder or otherwise existing at law, in equity or otherwise, of the General Partner or its Affiliates to the Partnership or the Limited Partners by reason of the fact that the purpose or effect of such borrowing is directly or indirectly to enable distributions to the General Partner or its Affiliates (including in their capacities as Limited Partners), including distributions that exceed the General Partner's Percentage Interest of the total amount distributed to all Partners.

SECTION 7.8. *Indemnification*.

(a) To the fullest extent permitted by law but subject to the limitations expressly provided in this Agreement, all Indemnitees shall be indemnified and held harmless by the Partnership from and against any and all losses, claims, damages, liabilities, joint or several, expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all threatened, pending or completed claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, and whether formal or informal and including appeals, in which any Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as an Indemnitee and acting (or refraining to act) in such capacity on behalf of or for the benefit of the Partnership; *provided* that the Indemnitee shall not be indemnified and held harmless pursuant to this Agreement if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Agreement, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful. Any indemnification pursuant to this Section 7.8 shall be made only out of the assets of the Partnership, it being agreed that the General Partner shall not be personally liable for such indemnification and shall have no obligation to contribute or loan any monies or property to the Partnership to enable it to effectuate such indemnification.

(b) To the fullest extent permitted by law, expenses (including legal fees and expenses) incurred by an Indemnitee who is indemnified pursuant to Section 7.8(a) in appearing at, participating in or defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the Partnership prior to a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Section 7.8, the Indemnitee is not entitled to be indemnified upon receipt by the Partnership of any undertaking by or on behalf of the Indemnitee to repay such amount if it shall be ultimately determined that the Indemnitee is not entitled to be indemnified as authorized by this Section 7.8.

(c) The indemnification provided by this Section 7.8 shall be in addition to any other rights to which an Indemnitee may be entitled under any agreement, pursuant to any vote of the holders of Outstanding Limited Partner Interests, as a matter of law, in equity or otherwise, both as to actions in the Indemnitee's capacity as an Indemnitee and as to actions in any other capacity, and shall continue as to an Indemnitee who has ceased to serve in such capacity and shall inure to the benefit of the heirs, successors, assigns and administrators of the Indemnitee.

(d) The Partnership may purchase and maintain (or reimburse the General Partner or its Affiliates for the cost of) insurance, on behalf of the General Partner, its Affiliates, the Indemnitees and such other Persons as the General Partner shall determine, against any liability that may be asserted against, or expense that may be incurred by, such Person in connection with the Partnership's activities or such Person's activities on behalf of the Partnership, regardless of whether the Partnership would have the power to indemnify such Person against such liability under the provisions of this Agreement.

(e) For purposes of this Section 7.8, the Partnership shall be deemed to have requested an Indemnitee to serve as fiduciary of an employee benefit plan whenever the performance by it of its duties to the Partnership also imposes duties on, or otherwise involves services by, it to the plan or participants or beneficiaries of the plan; excise taxes assessed on an Indemnitee with respect to an employee benefit plan pursuant to applicable law shall constitute "fines" within the meaning of Section 7.8(a); and action taken or omitted by it with respect to any employee benefit plan in the performance of its duties for a purpose reasonably believed by it to be in the best interest of the participants and beneficiaries of the plan shall be deemed to be for a purpose that is in the best interests of the Partnership.

(f) In no event may an Indemnitee subject the Limited Partners to personal liability by reason of the indemnification provisions set forth in this Agreement.

(g) An Indemnitee shall not be denied indemnification in whole or in part under this Section 7.8 because the Indemnitee had an interest in the transaction with respect to which the indemnification applies.

(h) The provisions of this Section 7.8 are for the benefit of the Indemnitees and their heirs, successors, assigns, executors and administrators and shall not be deemed to create any rights for the benefit of any other Persons.

(i) No amendment, modification or repeal of this Section 7.8 or any provision hereof shall in any manner terminate, reduce or impair the right of any past, present or future Indemnitee to be indemnified by the Partnership, nor the obligations of the Partnership to indemnify any such Indemnitee under and in accordance with the provisions of this Section 7.8 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may arise or be asserted.

SECTION 7.9. *Liability of Indemnitees*.

(a) Notwithstanding anything to the contrary set forth in this Agreement, no Indemnitee shall be liable for monetary damages to the Partnership, the Limited Partners, any other Persons who acquire an interest in a Partnership Interest or any other Person who is bound by this Agreement, for losses sustained or liabilities incurred as a result of any act or omission of an Indemnitee unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was criminal. The Limited Partners, any other Person who acquires an interest in a Partnership Interest and any other Person who is bound by this Agreement, each on their own behalf and on behalf of the Partnership, waives any and all rights to claim punitive damages or damages based upon the Federal or State income taxes paid or payable by any such Limited Partner or other Person.

(b) Subject to its obligations and duties as General Partner set forth in Section 7.1(a), the General Partner may exercise any of the powers granted to it by this Agreement and perform any of the duties imposed upon it hereunder either directly or by or through its agents, and the General Partner shall not be responsible for any misconduct or negligence on the part of any such agent appointed by the General Partner in good faith.

(c) To the extent that, at law or in equity, an Indemnitee has duties and liabilities relating thereto to the Partnership, the Partners, any Person who acquires an interest in a Partnership Interest or any other Person who is bound by this Agreement, any Indemnitee acting in connection with the Partnership's business or affairs shall not be liable, to the fullest extent permitted by law, to the Partnership, to any Partner, to any other Person who acquires an interest in a Partnership Interest or to any other Person who is bound by this Agreement for its reliance on the provisions of this Agreement.

(d) Any amendment, modification or repeal of this Section 7.9 or any provision hereof shall be prospective only and shall not in any way affect the limitations on the liability of the Indemnitees under this Section 7.9 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may arise or be asserted.

SECTION 7.10. *Resolution of Conflicts of Interest; Standards of Conduct and Modification of Duties*.

(a) Unless otherwise expressly provided in this Agreement, whenever a potential conflict of interest exists or arises between the General Partner or any of its Affiliates (other than the Partnership, any Group Member or any Partner), on the one hand, and the Partnership, any Group Member or any Partner, on the other, any resolution or course of action by the General Partner or its Affiliates in respect of such conflict of interest (including any course of action pursuant to Articles XIII, XIV and XV) shall conclusively be permitted and deemed approved by all Partners, and shall not constitute a breach of this Agreement, or of any agreement contemplated herein, or of any duty stated hereunder or implied by law or equity or otherwise, if the resolution or course of action in respect of such conflict of interest is (i) approved by Special Approval, (ii) approved by the vote of a majority of the Outstanding Common Units (excluding Common Units owned by the General Partner and its Affiliates), (iii) on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties or (iv) fair and reasonable to the Partnership, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to the Partnership). The General Partner shall be authorized but not required in connection with its resolution of such conflict of interest to seek Special Approval or Unitholder approval of such resolution, and the General Partner may also adopt a resolution or course of action that has not received Special Approval or Unitholder approval. If Special Approval is sought, then it shall be presumed that, in making its decision, the Conflicts Committee acted in good faith, and if neither Special Approval nor Unitholder approval is sought and the Board of Directors determines that the resolution or course of action taken with respect to a conflict of interest satisfies either of the standards set forth in clauses (iii) or (iv) above, then it shall be presumed that, in making its decision, the Board of Directors acted in good faith, and in either case, in any proceeding brought by any Limited Partner or by or on behalf of such Limited Partner or any other Limited Partner or the Partnership challenging such approval, the Person bringing or prosecuting such proceeding shall have the burden of overcoming such presumption. Notwithstanding anything to the contrary in this Agreement or any duty otherwise existing at law or equity, the existence of the conflicts of interest described in the Registration Statement and any actions of the General Partner taken in connection therewith are hereby approved by all Partners and shall not constitute a breach of this Agreement or of any duty hereunder or existing at law, in equity or otherwise.

(b) Whenever the General Partner, the Board of Directors or any committee of the Board of Directors (including the Conflicts Committee), makes a determination or takes or declines to take any other action, or any Affiliate of the General Partner causes the General Partner to do so, in its capacity as the general partner of the Partnership as opposed to in its individual capacity, whether under this Agreement or any other agreement contemplated hereby or otherwise, then, unless another express standard is provided for in this Agreement, the General Partner, the Board of Directors, such committee or such Affiliate causing the General Partner, in its capacity as the general partner of the Partnership as opposed to in its individual capacity, to do so, shall make such determination or take or decline to take such other action in good faith and shall not be subject to any other or different standards imposed by this Agreement, any other agreement contemplated hereby or under the Delaware Act or any other law, rule or regulation or at equity (including fiduciary standards). A determination, other action or failure to act by the General Partner, the Board of Directors, any committee of the Board of Directors (including the Conflicts Committee), or such Affiliate causing the General Partner to do so, will be deemed to be in good faith unless the applicable party believed such determination, other action or failure to act was adverse to the interests of the Partnership. In any proceeding brought by the Partnership, any Limited Partner, any Person who acquires an interest in a Partnership Interest or any other Person who is bound by this Agreement challenging such action, determination or failure to act, the Person bringing or prosecuting such proceeding shall have the burden of proving that such determination, action or failure to act was not in good faith.

(c) Whenever the General Partner or any of its Affiliates or any other Indemnitee makes a determination or takes or declines to take any other action, or any Affiliate of the General Partner causes the General Partner to do so, in the General Partner's individual capacity as opposed to in its capacity as the general partner of the Partnership, whether under this Agreement or any other agreement contemplated hereby or otherwise, then the General Partner, such Affiliates and such Indemnitee are entitled, to the fullest extent permitted by law, to make such determination or to take or decline to take such other action free of any duty existing at law, in equity or otherwise or obligation whatsoever to the Partnership, any Partner, any other Person who acquires an interest in a Partnership Interest or any other Person bound by this Agreement, and the General Partner, such Affiliates and such Indemnitee shall not, to the fullest extent permitted by law, be required to act in good faith or pursuant to any other standard imposed by this Agreement, any other agreement contemplated hereby or under the Delaware Act or any other law, rule or regulation or at equity. By way of illustration and not of limitation, whenever the phrases, "at the option of the General Partner," "in its discretion" or some variation of those phrases, are used in this Agreement, it indicates that the General Partner is acting in its individual capacity. For the avoidance of doubt, whenever the General Partner, any of its Affiliates or any Indemnitee votes or transfers its Partnership Interests or refrains from voting or transferring its Partnership Interests, it shall be acting in its individual capacity. The General Partner's organizational documents may provide that determinations to take or decline to take any action in its individual, rather than representative, capacity may or shall be determined by its members, if the General Partner is a limited liability company, stockholders, if the General Partner is a corporation, or the members or stockholders of the General Partner's general partner, if the General Partner is a partnership.

(d) Notwithstanding anything to the contrary in this Agreement, none of the General Partner, any Affiliate of the General Partner or any Indemnitee shall have any duty or obligation, express or implied, to (i) sell or otherwise dispose of any asset of or equity interest in the Partnership Group or (ii) permit any Group Member to use any facilities or assets of the General Partner, its Affiliates or any Indemnitee, except as may be provided in any definitive agreement entered into from time to time specifically dealing with such use. Any determination by the General Partner, any of its Affiliates or Indemnitee to enter into such contracts shall be in its sole discretion.

(e) The Limited Partners, each Person who acquires an interest in a Partnership Interest and each other Person who is bound by this Agreement hereby authorize the General Partner, on behalf of the Partnership as a partner or member of a Group Member, to approve actions by the general partner or managing member of such Group Member similar to those actions permitted to be taken by the General Partner pursuant to this Section 7.10.

(f) Nothing in this Section 7.10 shall be deemed to expand any duties or liabilities of the General Partner, its Affiliates or any other Indemnitee to the Partnership, any Group Member, any Partner, any Person who acquires an interest in a Partnership Interest or other person who is bound by this Agreement for breach of this Agreement, to the extent that those duties or liabilities shall have been limited pursuant to Section 7.2, 7.6 or 7.10.

SECTION 7.11. *Other Matters Concerning the General Partner*.

(a) The General Partner may rely upon, and shall be protected in acting or refraining from acting upon, any resolution, certificate, statement, instrument, opinion, report, notice, request, consent, order, bond, debenture or other paper or document believed by it to be genuine and to have been signed or presented by the proper party or parties.

(b) The General Partner may consult with legal counsel, accountants, appraisers, management consultants, investment bankers and other consultants and advisers selected by it, and any act taken or omitted to be taken in reliance upon the advice or opinion (including an Opinion of Counsel) of such Persons as to matters that the General Partner reasonably believes to be within such Person's professional or expert competence shall be conclusively presumed to have been done or omitted in good faith and in accordance with such advice or opinion.

(c) The General Partner shall have the right, in respect of any of its powers or obligations hereunder, to act through any of its duly authorized officers, a duly appointed attorney or attorneys-in-fact or the duly authorized officers of the Partnership or any Group Member.

SECTION 7.12. *Purchase or Sale of Partnership Interests*.

The General Partner may cause the Partnership to purchase or otherwise acquire Partnership Interests. As long as Partnership Interests are held by any Group Member, such Partnership Interests shall not be considered Outstanding for any purpose, except as otherwise provided herein. The General Partner or any Affiliate of the General Partner may also purchase or otherwise acquire and sell or otherwise dispose of Partnership Interests for its own account, subject to the provisions of Articles IV and X.

SECTION 7.13. *Registration Rights of the General Partner and its Affiliates*

(a) If (i) the General Partner or any Affiliate of the General Partner or the Partnership (including for purposes of this Section 7.13, any Person that is an Affiliate of the General Partner or Partnership at the date hereof notwithstanding that it may later cease to be an Affiliate of the General Partner or Partnership, including, if permitted by the General Partner, individual Affiliates who are officers, directors or employees of the General Partner or any of its Affiliates) holds Partnership Interests that it desires to sell and (ii) Rule 144 of the Securities Act (or any successor rule or regulation to Rule 144) or another exemption from registration is not available to enable such holder of Partnership Interests (the "*Holder*") to dispose of the number of Partnership Interests it desires to sell at the time, in such manner and in such amounts as it desires without registration under the Securities Act, then at the option and upon the request of the Holder, the Partnership shall file with the Commission as promptly as practicable after receiving such request, and use all commercially reasonable efforts to cause to become effective and remain effective for a period of not less than six months following its effective date or such shorter period as shall terminate when all Partnership Interests covered by such registration statement have been sold, a registration statement under the Securities Act registering the offering and sale of the number of Partnership Interests specified by the Holder; *provided*, *however*, that if the Conflicts Committee (which may be requested to review the matter by any member of the Board of Directors) determines in good faith that the requested registration would be materially detrimental to the Partnership and its Partners because such registration would (A) materially interfere with a significant acquisition, reorganization or other similar transaction involving the Partnership; or (B) require premature disclosure of material information that the Partnership has a bona fide business purpose for preserving as confidential, then the Partnership shall have the right to postpone such requested registration for a period of not more than six months after receipt of the Holder's request, such right to postpone not to be used more than once in any 12-month period. In connection with any registration pursuant to the immediately preceding sentence, the Partnership shall (i) promptly prepare and file (A) such documents as may be necessary to register or qualify the securities subject to such registration under the securities laws of such states as the Holder shall reasonably request; *provided*, *however*, that no such qualification shall be required in any jurisdiction where, as a result thereof, the Partnership would become subject to general service of process or to taxation or qualification to do business as a foreign corporation or partnership doing business in such jurisdiction solely as a result of such registration, and (B) such documents as may be necessary to apply for listing or to list the Partnership Interests subject to such registration on such National Securities Exchange as the Holder shall reasonably request, and (ii) do any and all other acts and things that may be necessary or appropriate to enable the Holder to consummate a public sale of such Partnership Interests in such states. Except as set forth in Section 7.13(c), all costs and expenses of any such registration and offering (other than the underwriting discounts and commissions) shall be paid by the Partnership, without reimbursement by the Holder. It is expressly understood that there shall be no limit on the number of registration demands pursuant to this Section 7.13.

(b) If the Partnership shall at any time propose to file a registration statement under the Securities Act for an offering of Partnership Interests for cash (other than an offering relating solely to a benefit plan or a registration statement relating solely to a Rule 145 transaction), the Partnership shall use all commercially reasonable efforts to include such number or amount of Partnership Interests held by any Holder in such registration statement as the Holder shall request; *provided* that the Partnership is not required to make any effort or take any action to so include the Partnership Interests of the Holder once the registration statement is declared effective by the Commission or otherwise becomes effective under the Securities Act, including any registration statement providing for the offering from time to time of Partnership Interests pursuant to Rule 415 of the

Securities Act. If the proposed offering pursuant to this Section 7.13(c) shall be an underwritten offering, then, in the event that the managing underwriter or managing underwriters of such offering advise the Partnership and the Holder in writing that in their opinion the inclusion of all or some of the Holder's Partnership Interests would adversely and materially affect the timing or success of the offering, the Partnership shall include in such offering only that number or amount, if any, of Partnership Interests held by the Holder that, in the opinion of the managing underwriter or managing underwriters, will not so adversely and materially affect the offering. Except as set forth in Section 7.13(c), all costs and expenses of any such registration and offering (other than the underwriting discounts and commissions) shall be paid by the Partnership, without reimbursement by the Holder.

(c) If underwriters are engaged in connection with any registration referred to in this Section 7.13, the Partnership shall provide indemnification, representations, covenants, opinions and other assurance to the underwriters in form and substance reasonably satisfactory to such underwriters. Further, in addition to and not in limitation of the Partnership's obligation under Section 7.8, the Partnership shall, to the fullest extent permitted by law, indemnify and hold harmless the Holder, its officers, directors and each Person who controls the Holder (within the meaning of the Securities Act) and any agent thereof (collectively, "*Indemnified Persons*") from and against any and all losses, claims, damages, liabilities (joint or several) and expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any Indemnified Person may be involved, or is threatened to be involved, as a party or otherwise, under the Securities Act or otherwise (hereinafter referred to in this Section 7.13(c) as a "*claim*" and in the plural as "*claims*") based upon, arising out of or resulting from any untrue statement or alleged untrue statement of any material fact contained in any registration statement under which any Partnership Interests were registered under the Securities Act or any state securities or Blue Sky laws, in any preliminary prospectus (if used prior to the effective date of such registration statement), or in any summary or final prospectus or any free writing prospectus or in any amendment or supplement thereto (if used during the period the Partnership is required to keep the registration statement current), or arising out of, based upon or resulting from the omission or alleged omission to state therein a material fact required to be stated therein or necessary to make the statements made therein not misleading; *provided*, *however*, that the Partnership shall not be liable to any Indemnified Person to the extent that any such claim arises out of, is based upon or results from an untrue statement or alleged untrue statement or omission or alleged omission made in such registration statement, such preliminary, summary or final prospectus or any free writing prospectus or such amendment or supplement, in reliance upon and in conformity with written information furnished to the Partnership by or on behalf of such Indemnified Person specifically for use in the preparation thereof.

(d) The provisions of Section 7.13(a) and 7.13(b) shall continue to be applicable with respect to the General Partner (and any of the General Partner's Affiliates) after it ceases to be a general partner of the Partnership or after the Affiliate of the General Partner ceases to be an Affiliate of the General Partner, during a period of two years subsequent to the effective date of such cessation and for so long thereafter as is required for the Holder to sell all of the Partnership Interests with respect to which it has requested during such two-year period inclusion in a registration statement otherwise filed or that a registration statement be filed. The provisions of Section 7.13(c) shall continue in effect thereafter.

(e) The rights to cause the Partnership to register Partnership Interests pursuant to this Section 7.13 may be assigned (but only with all related obligations) by a Holder to a transferee or assignee of some or all of such Holder's Partnership Interests; *provided* that (i) the Partnership is, within a reasonable time after such transfer, furnished with written notice of the name and address of such transferee or assignee and the Partnership Interests with respect to which such registration rights are being assigned; and (ii) such transferee or assignee agrees in writing to be bound by and subject to the terms set forth in this Section 7.13 as if such transferee or assignee were a Holder.

(f) Any request to register Partnership Interests pursuant to this Section 7.13 shall (i) specify the Partnership Interests intended to be offered and sold by the Person making the request, (ii) express such Person's present intent to offer such Partnership Interests for distribution, (iii) describe the nature or method of the proposed offer and sale of Partnership Interests and (iv) contain the undertaking of such Person to provide all such information and materials and take all action as may be required in order to permit the Partnership to comply with all applicable requirements in connection with the registration of such Partnership Interests.

(g) The Partnership agrees to use commercially reasonable efforts to take all actions and deliver, or cause to be delivered, all prospectuses, supplemental prospectuses and any free writing prospectuses to Holders, as directed by Holders, as required by applicable law.

SECTION 7.14. *Reliance by Third Parties*.

Notwithstanding anything to the contrary in this Agreement, any Person dealing with the Partnership shall be entitled to assume that the General Partner and any officer of the General Partner authorized by the General Partner to act on behalf of and in the name of the Partnership has full power and authority to encumber, sell or otherwise use in any manner any and all assets of the Partnership and to enter into any authorized contracts on behalf of the Partnership, and such Person shall be entitled to deal with the General Partner or any such officer as if it were the Partnership's sole party in interest, both legally and beneficially. Each of the Limited Partners, each other Person who acquires an interest in a Partnership Interest and each other Person who is bound by this Agreement hereby waives, to the fullest extent permitted by law, any and all defenses or other remedies that may be available against such Person to contest, negate or disaffirm any action of the General Partner or any such officer in connection with any such dealing. In no event shall any Person dealing with the General Partner or any such officer or its representatives be obligated to ascertain that the terms of this Agreement have been complied with or to inquire into the necessity or expedience of any act or action of the General Partner or its representatives. Each and every certificate, document or other instrument executed on behalf of the Partnership by the General Partner or any such officer or its representatives shall be conclusive evidence in favor of any and every Person relying thereon or claiming thereunder that (a) at the time of the execution and delivery of such certificate, document or instrument, this Agreement was in full force and effect, (b) the Person executing and delivering such certificate, document or instrument was duly authorized and empowered to do so for and on behalf of the Partnership and (c) such certificate, document or instrument was duly executed and delivered in accordance with the terms and provisions of this Agreement and is binding upon the Partnership.

ARTICLE VIII

BOOKS, RECORDS, ACCOUNTING AND REPORTS

SECTION 8.1. *Records and Accounting*

The General Partner shall keep or cause to be kept at the principal office of the Partnership appropriate books and records with respect to the Partnership's business, including all books and records necessary to provide to the Limited Partners any information required to be provided pursuant to Section 3.4(a). Any books and records maintained by or on behalf of the Partnership in the regular course of its business, including the record of the Record Holders of Units or other Partnership Interests, books of account and records of Partnership proceedings, may be kept on, or be in the form of, computer disks, hard drives, punch cards, magnetic tape, photographs, micrographics or any other information storage device; *provided*, that the books and records so maintained are convertible into clearly legible written form within a reasonable period of time. The books of the Partnership shall be maintained, for financial reporting purposes, on an accrual basis in accordance with U.S. GAAP. The Partnership shall not be required to keep books maintained on a cash basis, and the General Partner shall be permitted to calculate cash-based measures, including Operating Surplus and Adjusted Operating Surplus, by making such adjustments to its accrual basis books to account for non-cash items and other adjustments as the General Partner determines to be necessary or appropriate.

SECTION 8.2. *Fiscal Year*

The fiscal year of the Partnership shall be a calendar year ending December 31.

SECTION 8.3. *Reports*

(a) As soon as practicable, but in no event later than 120 days after the close of each fiscal year of the Partnership, the General Partner shall cause to be furnished or made available, by any reasonable means (including posting on or making accessible through the Partnership's or the SEC's website) to each Record Holder of a Partnership Interest as of a date selected by the General Partner, an annual report containing financial statements of the Partnership for such fiscal year of the Partnership, presented in accordance with U.S. GAAP, including a balance sheet and statements of operations, Partnership equity and cash flows, such statements to be audited by a firm of independent public accountants selected by the General Partner.

(b) As soon as practicable, but in no event later than 90 days after the close of each Quarter except the last Quarter of each fiscal year, the General Partner shall cause to be furnished or made available, by any reasonable means (including posting on or making accessible through the Partnership's or the SEC's website) to each Record Holder of a Partnership Interest, as of a date selected by the General Partner in its discretion, a report containing unaudited financial statements of the Partnership and such other information as may be required by applicable law, regulation or rule of any National Securities Exchange on which the Units are listed or admitted for trading, or as the General Partner determines to be necessary or appropriate.

ARTICLE IX

TAX MATTERS

SECTION 9.1. *Tax Returns and Information*

The Partnership shall timely file all returns of the Partnership that are required for federal, state and local income tax purposes on the basis of the accrual method and the taxable year that it is required by law to adopt, from time to time, as determined by the General Partner. In the event the Partnership is required to use a taxable year other than a year ending on December 31, the General Partner shall use reasonable efforts to change the taxable year of the Partnership to a year ending on December 31. The tax information reasonably required by Record Holders for federal and state income tax reporting purposes with respect to a taxable year shall be furnished to them within 90 days of the close of the calendar year in which the Partnership's taxable year ends, provided that, if the 90^{th} day is not a Business Day, then the 90^{th} day shall be deemed to be the next Business Day. The classification, realization and recognition of income, gain, losses and deductions and other items shall be on the accrual method of accounting for U.S. federal income tax purposes.

SECTION 9.2. *Tax Elections*

(a) The Partnership shall make the election under Section 754 of the Code in accordance with applicable regulations thereunder, subject to the reservation of the right to seek to revoke any such election upon the General Partner's determination that such revocation is in the best interests of the Limited Partners. Notwithstanding any other provision herein contained, for the purposes of computing the adjustments under Section 743(b) of the Code, the General Partner shall be authorized (but not required) to adopt a convention whereby the price paid by a transferee of a Limited Partner Interest will be deemed to be the lowest quoted closing price of the Limited Partner Interests on any National Securities Exchange on which such Limited Partner Interests are listed or admitted for trading during the calendar month in which such transfer is deemed to occur pursuant to Section 6.2(g) without regard to the actual price paid by such transferee.

(b) Except as otherwise provided herein, the General Partner shall determine whether the Partnership should make any other elections permitted by the Code.

SECTION 9.3. *Tax Controversies*

Subject to the provisions hereof, the General Partner is designated as the Tax Matters Partner (as defined in the Code) and is authorized and required to represent the Partnership (at the Partnership's expense) in connection with all examinations of the Partnership's affairs by tax authorities, including resulting administrative and judicial proceedings, and to expend Partnership funds for professional services and costs associated therewith. Each Partner agrees to cooperate with the General Partner and to do or refrain from doing any or all things reasonably required by the General Partner to conduct such proceedings.

SECTION 9.4. *Withholding*

Notwithstanding any other provision of this Agreement, the General Partner is authorized to take any action that may be required to cause the Partnership and other Group Members to comply with any withholding requirements established under the Code or any other federal, state or local law (including pursuant to Sections 1441, 1442, 1445 and 1446 of the Code) or established under any foreign law. To the extent that the Partnership is required or elects to withhold and pay over to any taxing authority any amount resulting from the allocation or distribution of income to any Partner (including by reason of Section 1446 of the Code), the General Partner may treat the amount withheld as a distribution of cash pursuant to Section 6.3 or 12.4(c) in the amount of such withholding from such Partner.

ARTICLE X

ADMISSION OF PARTNERS

SECTION 10.1. *Admission of Limited Partners*

(a) By acceptance of the transfer of any Limited Partner Interests in accordance with Article IV or the acceptance of any Limited Partner Interests issued pursuant to Article V or pursuant to a merger, consolidation or conversion pursuant to Article XIV, and except as provided in Section 4.9, each transferee of, or other Person acquiring, a Limited Partner Interest (including any nominee holder or an agent or representative acquiring such Limited Partner Interests for the account of another Person) (i) shall be admitted to the Partnership as a Limited Partner with respect to the Limited Partner Interests so transferred or issued to such Person when any such transfer, issuance or admission is reflected in the books and records of the Partnership and such Person becomes the Record Holder of the Limited Partner Interests so transferred or issued, (ii) shall become bound by and shall be deemed to have agreed to be bound by the terms of, and shall be deemed to have executed, this Agreement, (iii) represents that such Person has the capacity, power and authority to enter into this Agreement, (iv) grants the powers of attorney set forth in this Agreement and (v) makes the consents, acknowledgements and waivers contained in this Agreement, in each case, with or without execution of this Agreement by such Person. The transfer or issuance of any Limited Partner Interests and the admission of any new Limited Partner shall not constitute an amendment to this Agreement. A Person may become a Limited Partner or a Record Holder of a Limited Partner Interest without the consent or approval of any of the Partners. A Person may not become a Limited Partner without acquiring a Limited Partner Interest and until such Person is reflected in the books and records of the Partnership as the Record Holder of such Limited Partner Interest. The rights and obligations of a Person who is an Ineligible Holder shall be determined in accordance with Section 4.9 hereof.

(b) The name and mailing address of each Limited Partner shall be listed on the books and records of the Partnership maintained for such purpose by the Partnership or the Transfer Agent. The General Partner shall update the books and records of the Partnership from time to time as necessary to reflect accurately the information therein (or shall cause the Transfer Agent to do so, as applicable). A Limited Partner Interest may be represented by a Certificate, as provided in Section 4.1 hereof.

(c) Any transfer of a Limited Partner Interest shall not entitle the transferee to share in the profits and losses, to receive distributions, to receive allocations of income, gain, loss, deduction or credit or any similar item or to any other rights to which the transferor was entitled until the transferee becomes a Limited Partner pursuant to Section 10.1(a).

SECTION 10.2. *Admission of Successor General Partner*.

A successor General Partner approved pursuant to Section 11.1 or 11.2 or the transferee of or successor to all of the General Partner Interest (represented by Class A Units) pursuant to Section 4.6 who is proposed to be admitted as a successor General Partner shall be admitted to the Partnership as the General Partner, effective immediately prior to the withdrawal or removal of the predecessor or transferring General Partner pursuant to Section 11.1 or 11.2 or the transfer of such General Partner's Interest (represented by Class A Units) pursuant to Section 4.6, *provided*, *however*, that no such successor shall be admitted to the Partnership until compliance with the terms of Section 4.6 has occurred and such successor has executed and delivered such other documents or instruments as may be required to effect such admission. Any such successor shall, subject to the terms hereof, shall be authorized to and shall carry on the business of the Partnership without dissolution.

SECTION 10.3. *Amendment of Agreement and Certificate of Limited Partnership*.

To effect the admission to the Partnership of any Partner, the General Partner shall take all steps necessary or appropriate under the Delaware Act to amend the records of the Partnership to reflect such admission and, if necessary, to prepare as soon as practicable an amendment to this Agreement and, if required by law, the General Partner shall prepare and file an amendment to the Certificate of Limited Partnership.

ARTICLE XI

WITHDRAWAL OR REMOVAL OF PARTNERS

SECTION 11.1. *Withdrawal of the General Partner*

(a) The General Partner shall be deemed to have withdrawn from the Partnership upon the occurrence of any one of the following events (each such event herein referred to as an "*Event of Withdrawal*"):

(i) the General Partner voluntarily withdraws from the Partnership by giving written notice to the other Partners;

(ii) the General Partner transfers all of its rights as General Partner pursuant to Section 4.6;

(iii) the General Partner is removed pursuant to Section 11.2;

(iv) the General Partner (A) makes a general assignment for the benefit of creditors; (B) files a voluntary bankruptcy petition for relief under Chapter 7 of the United States Bankruptcy Code; (C) files a petition or answer seeking for itself a liquidation, dissolution or similar relief (but not a reorganization) under any law; (D) files an answer or other pleading admitting or failing to contest the material allegations of a petition filed against the General Partner in a proceeding of the type described in clauses (A)-(C) of this Section 11.1(a)(iv); or (E) seeks, consents to or acquiesces in the appointment of a trustee (but not a debtor-in-possession), receiver or liquidator of the General Partner or of all or any substantial part of its properties;

(v) a final and non-appealable order of relief under Chapter 7 of the United States Bankruptcy Code is entered by a court with appropriate jurisdiction pursuant to a voluntary or involuntary petition by or against the General Partner; or

(vi) (A) in the event the General Partner is a corporation, a certificate of dissolution or its equivalent is filed for the General Partner, or 90 days expire after the date of notice to the General Partner of revocation of its charter without a reinstatement of its charter, under the laws of its state of incorporation; (B) in the event the General Partner is a partnership or a limited liability company, the dissolution and commencement of winding up of the General Partner; (C) in the event the General Partner is acting in such capacity by virtue of being a trustee of a trust, the termination of the trust; (D) in the event the General Partner is a natural person, his death or adjudication of incompetency; and (E) otherwise in the event of the termination of the General Partner.

If an Event of Withdrawal specified in Section 11.1(a)(iv), 11.1(a)(v), 11.1(a)(vi)(A), 11.1(a)(vi)(B), 11.1(a)(vi)(C) or 11.1(a)(vi)(E) occurs, the withdrawing General Partner shall give notice to the Limited Partners within 30 days after such occurrence. The Partners hereby agree that only the Events of Withdrawal described in this Section 11.1 shall result in the withdrawal of the General Partner from the Partnership.

(b) Withdrawal of the General Partner from the Partnership upon the occurrence of an Event of Withdrawal shall not constitute a breach of this Agreement under the following circumstances: (i) at any time during the period beginning on the Closing Date and ending at 12:00 midnight, Eastern Time, on the tenth anniversary of the date of the Initial Distribution, the General Partner voluntarily withdraws by giving at least 90 days' advance notice of its intention to withdraw to the Limited Partners; *provided* that prior to the effective date of such withdrawal, the withdrawal is approved by Unitholders holding at least a majority of the Outstanding Common Units (excluding Common Units held by the General Partner and its Affiliates) and the General Partner delivers to the Partnership an Opinion of Counsel ("*Withdrawal Opinion of Counsel*") that such withdrawal (following the selection of the successor General Partner) would not result in the loss of the limited liability under the Delaware Act of any Limited Partner or cause any Group Member to be treated as an association taxable as a corporation or otherwise to be taxed as an entity for U.S. federal income tax purposes (to the extent not already treated or taxed as such); (ii) at any time after 12:00 midnight, Eastern Time, on the tenth anniversary of the date of the Initial Distribution, the General Partner voluntarily withdraws by giving at least 90 days' advance notice to the Unitholders, such withdrawal to take effect on the date specified in such notice; (iii) at any time that the General Partner ceases to be the General Partner pursuant to clause (ii) or is removed pursuant to Section 11.2; or (iv) notwithstanding clause (i) of this sentence, at any time that the General Partner voluntarily withdraws by giving at least 90 days' advance notice of its intention to withdraw to the Limited Partners, such withdrawal to take effect on the date specified in the notice, if, at the time such notice is given, one Person and its Affiliates (other than the General Partner and its Affiliates) own beneficially or of record or control at least 50% of the Outstanding Units. The withdrawal of the General Partner from the Partnership upon the occurrence of an Event of Withdrawal shall also constitute the withdrawal of the General Partner as general partner or managing member, if any, to the extent applicable, of the other Group Members. If the General Partner gives a notice of withdrawal pursuant to Section 11.1(a)(i), the holders of a Unit Majority, may, prior to the effective date of such withdrawal, elect a successor General Partner. The Person so elected as successor General Partner shall automatically become the successor general partner or managing member, to the extent applicable, of the other Group Members of which the General Partner is a general partner or a managing member. If, prior to the effective date of the General Partner's withdrawal pursuant to Section 11.1(a)(i) above, a successor is not selected by the Unitholders as provided herein or the Partnership does not receive a Withdrawal Opinion of Counsel, the Partnership shall be dissolved in accordance with Section 12.1 unless the business of the Partnership is continued pursuant to Section 12.2. Any successor General Partner elected in accordance with the terms of this Section 11.1 shall be subject to the provisions of Section 10.2.

SECTION 11.2. *Removal of the General Partner*

The General Partner may be removed if such removal is approved by the Unitholders holding at least two-thirds of the Outstanding Common Units (including Common Units held by the General Partner and its Affiliates). Any such action by such holders for removal of the General Partner must also provide for the election of a successor General Partner by the Unitholders holding a majority of Outstanding Common Units (including Common Units held by the General Partner and its Affiliates). Such removal shall be effective immediately following the admission of a successor General Partner pursuant to Section 10.2. The removal of the General Partner shall also automatically constitute the removal of the General Partner as general partner or managing member, to the extent applicable, of the other Group Members of which the General Partner is a general partner or a managing member. If a Person is elected as a successor General Partner in accordance with the terms of this Section 11.2, such Person shall, upon admission pursuant to Section 10.2, automatically become a successor general partner or managing member, to the extent applicable, of the other Group Members of which the General Partner is a general partner or a managing member. The right of the holders of Outstanding Units to remove the General Partner shall not exist or be exercised unless the Partnership has received an opinion opining as to the matters covered by a Withdrawal Opinion of Counsel. Any successor General Partner elected in accordance with the terms of this Section 11.2 shall be subject to the provisions of Section 10.2.

SECTION 11.3. *Interest of Departing General Partner and Successor General Partner*

(a) In the event of (i) withdrawal of the General Partner under circumstances where such withdrawal does not violate this Agreement or (ii) removal of the General Partner by the holders of Outstanding Common Units under circumstances where Cause does not exist, if the successor General Partner is elected in accordance with the terms of Section 11.1 or 11.2, then the Departing General Partner shall have the option, exercisable prior to the effective date of the withdrawal or removal of such Departing General Partner, to require its successor to purchase any or all of the following, as determined by the Departing General Partner: (A) its General Partner Interest (represented by Class A Units), (B) its general partner interest (or equivalent interest), if any, in the other Group Members and/or (C) all of its or its Affiliates' Incentive Distribution Rights ((A), (B) and/or (C), as determined by the Departing General Partner, the "*Combined Interest*"), in exchange for an amount in cash equal to the fair market value of such Combined Interest, such amount to be determined and payable as of the effective date of its withdrawal or removal, or, if there is not agreement as to the fair market value of such Combined Interest at the effective date of such withdrawal or removal, within ten (10) days after such fair market value is determined pursuant to this Section 11.3(a). If the General Partner is removed by the Unitholders under circumstances where Cause exists or if the General Partner withdraws under circumstances where such withdrawal violates this Agreement, and if a successor General Partner is elected in accordance with the terms of Section 11.1 or 11.2 (or if the business of the Partnership is continued pursuant to Section 12.2 and the successor General Partner is not the former General Partner), such successor shall have the option, exercisable prior to the effective date of the withdrawal or removal of such Departing General Partner (or, in the event the business of the Partnership is continued, prior to the date the business of the Partnership is continued), to purchase all (and not less than all) of the items under clauses (A), (B) and (C) of the definition of Combined Interests of the Departing General Partner for such fair market value of such Combined Interest of the Departing General Partner. In either event, the Departing General Partner shall be entitled to receive all reimbursements due such Departing General Partner pursuant to Section 7.5, including any employee-related liabilities (including severance liabilities), incurred in connection with the termination of any employees employed by the Departing General Partner or its Affiliates for the benefit of the Partnership or the other Group Members.

For purposes of this Section 11.3(a), the fair market value of a Departing General Partner's Combined Interest shall be determined by agreement between the Departing General Partner and its successor or, failing agreement within 30 days after the effective date of such Departing General Partner's withdrawal or removal, by an independent investment banking firm or other independent expert selected by the Departing General Partner and its successor, which, in turn, may rely on other experts, and the determination of which shall be conclusive as to such matter. If such parties cannot agree upon one independent investment banking firm or other independent expert within 45 days after the effective date of such withdrawal or removal, then the Departing General Partner shall designate an independent investment banking firm or other independent expert, the Departing General Partner's successor shall designate an independent investment banking firm or other independent expert, and such firms or experts shall mutually select a third independent investment banking firm or independent expert, which third independent investment banking firm or other independent expert shall determine the fair market value of the Combined Interest of the Departing General Partner. In making its determination, such third independent investment banking firm or other independent expert may consider the then current trading price of Units on any National Securities Exchange on which Units are then listed or admitted for trading, the value of the Partnership's assets, the rights and obligations of the Departing General Partner, the value of the Incentive Distribution Rights and the General Partner Interest (represented by Class A Units) and other factors it may deem relevant, but shall not discount the value of the Combined Interest for illiquidity or minority interest status.

(b) If the Combined Interest is not purchased in the manner set forth in Section 11.3(a), the Departing General Partner (or its transferee) shall become a Limited Partner and its Combined Interest shall be converted into Common Units pursuant to a valuation determined by agreement between the Departing General Partner and its successor or, failing agreement within 30 days after the effective date of such Departing General Partner's withdrawal or removal, by an investment banking firm or other independent expert selected pursuant to (and following the guidelines set forth in) Section 11.3(a), without reduction in such Partnership Interest (but subject to proportionate dilution by reason of the admission of its successor). Any successor General Partner shall indemnify the Departing General Partner (or its transferee) as to all debts and liabilities of the Partnership arising on or after the date on which the Departing General Partner (or its transferee) becomes a Limited Partner. For purposes of this Agreement, conversion of the Combined Interest of the Departing General Partner to Common Units will be characterized as if such Departing General Partner (or its transferee) contributed its Combined Interest to the Partnership in exchange for the newly issued Common Units.

(c) If a successor General Partner is elected in accordance with the terms of Section 11.1 or 11.2 (or if the business of the Partnership is continued pursuant to Section 12.2 and the successor General Partner is not the former General Partner) and the option described in Section 11.3(a) is not exercised by the party entitled to do so, the successor General Partner shall, at the effective date of its admission to the Partnership, contribute to the Partnership cash in the amount equal to the product of (i) the quotient obtained by dividing (A) the Percentage Interest of the General Partner Interest of the Departing General Partner by (B) a percentage equal to 100% less the Percentage Interest of the General Partner Interest of the Departing General Partner and (ii) the Net Agreed Value of the Partnership's assets on such date. In such event, such successor General Partner shall, subject to the following sentence, be entitled to its Percentage Interest of all Partnership allocations and distributions to which the Departing General Partner was entitled. In addition, the successor General Partner shall cause this Agreement to be amended to reflect that, from and after the date of such successor General Partner's admission, the successor General Partner's interest in all Partnership distributions and allocations shall be its Percentage Interest.

SECTION 11.4. *Withdrawal of Limited Partners*.

(a) No Limited Partner shall have any right to withdraw from the Partnership; *provided*, *however*, that when a transferee of a Limited Partner's Limited Partner Interest becomes a Record Holder of the Limited Partner Interest so transferred, such transferring Limited Partner shall cease to be a Limited Partner with respect to the Limited Partner Interest so transferred.

ARTICLE XII

DISSOLUTION AND LIQUIDATION

SECTION 12.1. *Dissolution*

The Partnership shall not be dissolved by the admission of Additional Limited Partners or by the admission of a successor General Partner in accordance with the terms of this Agreement. Upon the removal or withdrawal of the General Partner, if a successor General Partner is elected pursuant to Section 11.1 or 11.2, the Partnership shall not be dissolved and such successor General Partner shall continue the business of the Partnership. The Partnership shall dissolve, and (subject to Section 12.2) its affairs shall be wound up, upon:

(a) an Event of Withdrawal of the General Partner as provided in Section 11.1(a) (other than Section 11.1(a)(ii)), unless a successor is elected and an Opinion of Counsel is received as provided in Section 11.1(b) or 11.2 and such successor is admitted to the Partnership pursuant to Section 10.2;

(b) an election to dissolve the Partnership by the General Partner that is approved by the holders of a Unit Majority;

(c) the entry of a decree of judicial dissolution of the Partnership pursuant to the provisions of the Delaware Act; or

(d) at any time there are no Limited Partners, unless the Partnership is continued without dissolution in accordance with the Delaware Act.

SECTION 12.2. *Continuation of the Business of the Partnership After Dissolution*

Upon (a) dissolution of the Partnership following an Event of Withdrawal caused by the withdrawal or removal of the General Partner as provided in Section 11.1(a)(i) or (iii) and the failure of the Partners to select a successor to such Departing General Partner pursuant to Section 11.1 or 11.2, then within 90 days thereafter, or (b) dissolution of the Partnership upon an event constituting an Event of Withdrawal as defined in Section 11.1(a)(iv), 11.1(a)(v) or 11.1(a)(vi), then, to the maximum extent permitted by law, within 180 days thereafter, the holders of a Unit Majority may elect to continue the business of the Partnership on the same terms and conditions set forth in this Agreement by appointing as a successor General Partner a Person approved by the holders of a Unit Majority. Unless such an election is made within the applicable time period as set forth above, the Partnership shall conduct only activities necessary to wind up its affairs. If such an election is so made, then:

(i) the Partnership shall continue without dissolution unless earlier dissolved in accordance with this Article XII;

(ii) if the successor General Partner is not the former General Partner, then the interest of the former General Partner shall be treated in the manner provided in Section 11.3; and

(iii) the successor General Partner shall be admitted to the Partnership as General Partner, effective as of the Event of Withdrawal, by agreeing in writing to be bound by this Agreement; *provided* that the right of the holders of a Unit Majority to approve a successor General Partner and to continue the business of the Partnership shall not exist and may not be exercised unless the Partnership has received an Opinion of Counsel that (x) the exercise of the right would not result in the loss of limited liability of any Limited Partner under the Delaware Act and (y) the Partnership would not be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of such right to continue (to the extent not already so treated or taxed).

SECTION 12.3. *Liquidator*

Upon dissolution of the Partnership, unless the business of the Partnership is continued pursuant to Section 12.2, the General Partner shall select one or more Persons to act as Liquidator. The Liquidator (if other than the General Partner) shall be entitled to receive such compensation for its services as may be approved by the holders of a Unit Majority. The Liquidator (if other than the General Partner) shall agree not to resign at any time without 15 days' prior notice and may be removed at any time, with or without cause, by notice of removal approved by the holders of a Unit Majority. Upon dissolution, removal or resignation of the Liquidator, a successor and substitute Liquidator (who shall have and succeed to all rights, powers and duties of the original Liquidator) shall within 30 days thereafter be approved by the holders of a Unit Majority. The right to approve a successor or substitute Liquidator in the manner provided herein shall be deemed to refer also to any such successor or substitute Liquidator approved in the manner herein provided. Except as expressly provided in this Article XII, the Liquidator approved in the manner provided herein shall have and may exercise, without further authorization or consent of any of the parties hereto, all of the powers conferred upon the General Partner under the terms of this Agreement (but subject to all of the applicable limitations, contractual and otherwise, upon the exercise of such powers, other than the limitation on sale set forth in Section 7.4) necessary or appropriate to carry out the duties and functions of the Liquidator hereunder for and during the period of time required to complete the winding up and liquidation of the Partnership as provided for herein.

SECTION 12.4. *Liquidation*

The Liquidator shall proceed to dispose of the assets of the Partnership, discharge its liabilities and otherwise wind up its affairs in such manner and over such period as determined by the Liquidator, subject to Section 17-804 of the Delaware Act and the following:

(a) *Disposition of Assets*. The assets may be disposed of by public or private sale or by distribution in kind to one or more Partners on such terms as the Liquidator and such Partner or Partners may agree; *provided* that no Partner agreement is necessary in respect of any pro rata distribution in kind of freely tradable publicly traded securities pursuant to this sentence. If any property is distributed in kind, the Partner receiving the property shall be deemed for purposes of Section 12.4(c) to have received cash equal to its fair market value; and, contemporaneously therewith, appropriate cash distributions must be made to the other Partners. The Liquidator may defer liquidation or distribution of the Partnership's assets for a reasonable time if it determines that an immediate sale or distribution of all or some of the Partnership's assets would be impractical or would cause undue loss to the Partners. The Liquidator may distribute the Partnership's assets, in whole or in part, in kind if it determines that a sale would be impractical or would cause undue loss to the Partners.

(b) *Discharge of Liabilities*. Liabilities of the Partnership include amounts owed to the Liquidator as compensation for serving in such capacity (subject to the terms of Section 12.3) and amounts owed to Partners otherwise than in respect of their distribution rights under Article VI. With respect to any liability that is contingent, conditional or unmatured or is otherwise not yet due and payable, the Liquidator shall either settle such claim for such amount as it thinks appropriate or establish a reserve of cash or other assets to provide for its payment. When paid, any unused portion of the reserve shall be distributed as additional liquidation proceeds.

(c) *Liquidation Distributions*. All property and all cash in excess of that required to discharge liabilities as provided in Section 12.4(b) shall be distributed to the Partners in accordance with, and to the extent of, the positive balances in their respective Capital Accounts, as determined after taking into account all Capital Account adjustments (other than those made by reason of distributions pursuant to this Section 12.4(c)) for the taxable year of the Partnership during which the liquidation of the Partnership occurs (with such date of occurrence being determined pursuant to Treasury Regulation Section 1.704-1(b)(2)(ii)(g)), and such distribution shall be made by the end of such taxable year (or, if later, within 90 days after said date of such occurrence).

SECTION 12.5. *Cancellation of Certificate of Limited Partnership*

Upon the completion of the distribution of Partnership cash and property as provided in Section 12.4 in connection with the liquidation of the Partnership, the Certificate of Limited Partnership and all qualifications of the Partnership as a foreign limited partnership in jurisdictions other than the State of Delaware shall be canceled and such other actions as may be necessary to terminate the Partnership shall be taken.

SECTION 12.6. *Return of Contributions*

The General Partner shall not be personally liable for, and shall have no obligation to contribute or loan any monies or property to the Partnership to enable it to effectuate, the return of the Capital Contributions of the Limited Partners or Unitholders, or any portion thereof, it being expressly understood that any such return shall be made solely from Partnership assets.

SECTION 12.7. *Waiver of Partition*

To the maximum extent permitted by law, each Partner hereby waives any right to partition of the Partnership property.

SECTION 12.8. *Capital Account Restoration*

No Limited Partner shall have any obligation to restore any negative balance in its Capital Account upon liquidation of the Partnership. The General Partner shall be obligated to restore any negative balance in its Capital Account upon liquidation of its interest in the Partnership by the end of the taxable year of the Partnership during which such liquidation occurs, or, if later, within 90 days after the date of such liquidation.

ARTICLE XIII

AMENDMENT OF PARTNERSHIP AGREEMENT; MEETINGS; RECORD DATE

SECTION 13.1. *Amendments to be Adopted Solely by the General Partner*

Each Partner agrees that the General Partner, without the approval of any Partner, may amend any provision of this Agreement and execute, swear to, acknowledge, deliver, file and record whatever documents may be required in connection therewith, to reflect:

(a) a change in the name of the Partnership, the location of the principal place of business of the Partnership, the registered agent of the Partnership or the registered office of the Partnership;

(b) admission, substitution, withdrawal or removal of Partners in accordance with this Agreement;

(c) a change that the General Partner determines to be necessary or appropriate to qualify or continue the qualification of the Partnership as a limited partnership or a partnership in which the Limited Partners have limited liability under the laws of any state or to ensure that the Group Members will not be treated as associations taxable as corporations or otherwise taxed as entities for U.S. federal income tax purposes;

(d) a change that the General Partner determines (i) does not adversely affect the Limited Partners (including any particular class of Partnership Interests as compared to other classes of Partnership Interests) in any material respect, (ii) to be necessary or appropriate to (A) satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute (including the Delaware Act) or (B) facilitate the trading of the Limited Partner Interests or Units (including the division of any class or classes of Outstanding Limited Partner Interests into different classes to facilitate uniformity of tax consequences within such classes of Limited Partner Interests) or comply with any rule, regulation, guideline or requirement of any National Securities Exchange on which the Limited Partner Interests or Units are or will be listed or admitted to trading, (iii) to be necessary or appropriate in connection with action taken by the General Partner pursuant to Section 5.7 or to implement the tax-related provisions of this Agreement or (iv) to be required to effect the intent expressed in the Registration Statement or the intent of the provisions of this Agreement or is otherwise contemplated by this Agreement;

(e) a change in the fiscal year or taxable year of the Partnership and any other changes that the General Partner determines to be necessary or appropriate as a result of a change in the fiscal year or taxable year of the Partnership including, if the General Partner shall so determine, a change in the definition of "Quarter" and the dates on which distributions are to be made by the Partnership;

(f) an amendment that is necessary, in the Opinion of Counsel, to prevent the Partnership, or the General Partner or its directors, officers, trustees or agents from in any manner being subjected to the provisions of the Investment Company Act of 1940, as amended, the Investment Advisers Act of 1940, as amended, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, as amended, regardless of whether such are substantially similar to plan asset regulations currently applied or proposed by the United States Department of Labor;

(g) an amendment that the General Partner determines to be necessary or appropriate in connection with the authorization or issuance of any class or series of Partnership Interests, or any options, warrants, rights and/or appreciation rights relating to any Partnership Interest, pursuant to Section 5.5;

(h) an amendment expressly permitted in this Agreement to be made by the General Partner acting alone;

(i) an amendment effected, necessitated or contemplated by a Merger Agreement or Plan of Conversion approved in accordance with Section 14.3, or an amendment contemplated by Section 14.6;

(j) an amendment that the General Partner determines to be necessary or appropriate to reflect and account for the formation by the Partnership of, or investment by the Partnership in, any corporation, partnership, joint venture, limited liability company or other entity, in connection with the conduct by the Partnership of activities permitted by the terms of Section 2.4;

(k) a merger, conveyance or conversion pursuant to Section 14.3(d);

(l) an amendment contemplated by Section 4.9; or

(m) any other amendments substantially similar to the foregoing.

SECTION 13.2. *Amendment Procedures*

Amendments to this Agreement may be proposed only by the General Partner. To the fullest extent permitted by law, the General Partner shall have no duty or obligation to propose or approve any amendment to this Agreement and may decline to do so in its sole discretion, free of any duty or obligation whatsoever to the Partnership or any Limited Partner and, in declining to propose or approve an amendment, to the fullest extent permitted by law, shall not be required to act in good faith or pursuant to any other standard imposed by this Agreement, any other agreement contemplated hereby or under the Delaware Act or any other law, rule or regulation or at equity. A proposed amendment shall be effective upon its approval by the General Partner and, except as otherwise provided in Section 13.1 or 13.3, the holders of a Unit Majority, unless a greater or different percentage of Outstanding Units is required under this Agreement or by Delaware law. Each proposed amendment that requires the approval of the holders of a specified percentage of Outstanding Units shall be set forth in a writing that contains the text of the proposed amendment. If such an amendment is proposed, the General Partner shall seek the written approval of the requisite percentage of Outstanding Units or call a meeting of the Unitholders to consider and vote on such proposed amendment. The General Partner shall notify all Record Holders upon final adoption of any such proposed amendments. The General Partner shall be deemed to have notified all Record Holders as required by this Section 13.2 if it has either (i) filed such amendment with the Commission via its Electronic Data Gathering, Analysis and Retrieval system (or any successor system) and such amendment is publicly available on such system or (ii) made such amendment available on any publicly available website maintained by or on behalf of the Partnership.

SECTION 13.3. *Amendment Requirements*

(a) Notwithstanding the provisions of Sections 13.1 and 13.2, no provision of this Agreement that establishes a percentage of Outstanding Units (including Units deemed owned by the General Partner and its Affiliates) required to take any action shall be amended, altered, changed, repealed or rescinded in any respect that would have the effect of (i) in the case of any provision of this Agreement other than Section 11.2 or 13.4, reducing such voting percentage or (ii) in the case of Section 11.2 or 13.4, increasing such percentage, in each of cases (i) and (ii) unless such amendment is approved by the written consent or the affirmative vote of holders of Outstanding Units whose aggregate Outstanding Units constitute not less than the voting requirement sought to be reduced or increased, as applicable.

(b) Notwithstanding the provisions of Sections 13.1 and 13.2, no amendment to this Agreement may (i) enlarge the obligations of any Limited Partner without its consent, unless such shall be deemed to have occurred as a result of an amendment approved pursuant to Section 13.3(c) or (ii) enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable to, the General Partner or any of its Affiliates without its consent, which consent may be given or withheld at its option.

(c) Except as provided in Section 14.3, and without limitation of the General Partner's authority to adopt amendments to this Agreement without the approval of any Partners as contemplated in Section 13.1, any amendment that would have a material adverse effect on the rights or preferences of any class of Partnership Interests in relation to other classes of Partnership Interests must be approved by the holders of not less than a majority of the Outstanding Partnership Interests of the class affected.

(d) Notwithstanding any other provision of this Agreement, except for amendments pursuant to Section 13.1 and except as otherwise provided by Section 14.3(b), no amendments shall become effective without the approval of the holders of at least 90% of the Outstanding Units voting as a single class if the General Partner determines that such amendment will affect the limited liability of any Limited Partner under applicable partnership law of the state under whose laws the Partnership is organized (it being understood that the General Partner may rely on any Opinion of Counsel in making such determination, but no such Opinion of Counsel shall be required).

(e) Except as provided in Section 13.1, this Section 13.3 shall only be amended with the approval of the holders of at least 90% of the Outstanding Units.

SECTION 13.4. *Special Meetings*

All acts of Limited Partners to be taken pursuant to this Agreement shall be taken in the manner provided in this Article XIII. Special meetings of the Limited Partners may be called by the General Partner or by Limited Partners owning 20% or more of the Outstanding Units of the class or classes for which a meeting is proposed. Limited Partners shall call a special meeting by delivering to the General Partner one or more requests in writing stating that the signing Limited Partners wish to call a special meeting and indicating the general or specific purposes for which the special meeting is to be called. Within 60 days after receipt of such a call from Limited Partners or within such greater time as may be reasonably necessary for the Partnership to comply with any statutes, rules, regulations, listing agreements or similar requirements governing the holding of a meeting or the solicitation of proxies for use at such a meeting, the General Partner shall send a notice of the meeting to the Limited Partners either directly or indirectly through the Transfer Agent. A meeting shall be held at a time and place determined by the General Partner on a date not less than 10 days nor more than 60 days after the time that notice of the meeting is provided as set forth in Section 16.1. Limited Partners shall not vote on matters that would cause the Limited Partners to be deemed to be taking part in the management and control of the business and affairs of the Partnership so as to jeopardize the Limited Partners' limited liability under the Delaware Act or the law of any other state in which the Partnership is qualified to do business.

SECTION 13.5. *Notice of a Meeting*

Notice of a meeting called pursuant to Section 13.4 shall be given to the Record Holders of the class or classes of Limited Partner Interests for which a meeting is proposed in writing by mail or other means of written communication in accordance with Section 16.1. The notice shall be deemed to have been given at the time when deposited in the mail or sent by other means of written communication.

SECTION 13.6. *Record Date*

For purposes of determining the Limited Partners entitled to notice of or to vote at a meeting of the Limited Partners or to give approvals without a meeting as provided in Section 13.11 the General Partner may set a Record Date, which shall not be less than 10 nor more than 60 days before (a) the date of the meeting (unless such requirement conflicts with any rule, regulation, guideline or requirement of any U.S. federal securities laws or any National Securities Exchange on which the Limited Partner Interests are listed or admitted for trading, in which case such U.S. federal securities laws or the rule, regulation, guideline or requirement of such National Securities Exchange shall govern) or (b) in the event that approvals are sought without a meeting, the date by which Limited Partners are requested in writing by the General Partner to give such approvals. If the General Partner does not set a Record Date, then (x) the Record Date for determining the Limited Partners entitled to notice of or to vote at a meeting of the Limited Partners shall be the close of business on the day immediately preceding the day on which notice is given, and (y) the Record Date for determining the Limited Partners entitled to give approvals without a meeting shall be the date the first written approval is deposited with the Partnership in care of the General Partner in accordance with Section 13.11.

SECTION 13.7. *Adjournment*

When a meeting is adjourned to another time or place, notice need not be given of the adjourned meeting and a new Record Date need not be fixed, if the time and place thereof are announced at the meeting at which the adjournment is taken, unless such adjournment shall be for more than 45 days. At the adjourned meeting, the Partnership may transact any business which might have been transacted at the original meeting. If the adjournment is for more than 45 days or if a new Record Date is fixed for the adjourned meeting, a notice of the adjourned meeting shall be given in accordance with this Article XIII.

SECTION 13.8. *Waiver of Notice; Approval of Meeting*

The transactions of any meeting of Limited Partners, however called and noticed, and whenever held, shall be as valid as if it had occurred at a meeting duly held after regular call and notice, if a quorum is present either in person or by proxy Attendance of a Limited Partner at a meeting shall constitute a waiver of notice of the meeting, except when the Limited Partner attends the meeting for the express purpose of objection, at the beginning of the meeting, to the transaction of any business because the meeting is not lawfully called or convened; and except that attendance at a meeting is not a waiver of any right to disapprove the consideration of matters required to be included in the notice of the meeting, but not so included, if the disapproval is expressly made at the meeting.

SECTION 13.9. *Quorum and Voting*

The holders of a majority of the Outstanding Units of the class or classes for which a meeting has been called (including the Outstanding Units owned or deemed owned by the General Partner or any of its Affiliates) represented in person or by proxy shall constitute a quorum at a meeting of Limited Partners of such class or classes unless any such action by the Limited Partners requires approval by holders of a greater percentage of such Units, in which case the quorum shall be such greater percentage. At any meeting of the Limited Partners duly called and held in accordance with this Agreement at which a quorum is present, the act of Limited Partners holding Outstanding Units that in the aggregate represent a majority of the Outstanding Units entitled to vote and be present in person or by proxy at such meeting shall be deemed to constitute the act of all Limited Partners, unless a greater or different percentage is required with respect to such action under the provisions of this Agreement, in which case the act of the Limited Partners holding Outstanding Units that in the aggregate represent at least such greater or different percentage shall be required. The Limited Partners present at a duly called or held meeting at which a quorum is present may continue to transact business until adjournment, notwithstanding the withdrawal of enough Limited Partners to leave less than a quorum, if any action taken (other than adjournment) is approved by the required percentage of Outstanding Units specified in this Agreement (including Outstanding Units deemed owned by the General Partner or any of its Affiliates). In the absence of a quorum, any meeting of Limited Partners may be adjourned from time to time by the affirmative vote of holders of at least a majority of the Outstanding Units entitled to vote at such meeting (including Outstanding Units deemed owned by the General Partner or its Affiliates) represented either in person or by proxy, but no other business may be transacted, except as provided in Section 13.7.

SECTION 13.10. *Conduct of a Meeting*

The General Partner shall have full power and authority concerning the manner of conducting any meeting of the Limited Partners or solicitation of approvals in writing, including the determination of Persons entitled to vote, the existence of a quorum, the satisfaction of the requirements of Section 13.4, the conduct of voting, the validity and effect of any proxies and the determination of any controversies, votes or challenges arising in connection with or during the meeting or voting. The General Partner shall designate a Person to serve as chairman of any meeting and shall further designate a Person to take the minutes of any meeting. All minutes shall be kept with the records of the Partnership maintained by the General Partner. The General Partner may make such other regulations consistent with applicable law and this Agreement as it may deem advisable concerning the conduct of any meeting of the Limited Partners or solicitation of approvals in writing, including regulations in regard to the appointment of proxies, the appointment and duties of inspectors of votes and approvals, the submission and examination of proxies and other evidence of the right to vote, and the revocation of approvals in writing.

SECTION 13.11. *Action Without a Meeting*

If authorized by the General Partner, any action that may be taken at a meeting of the Limited Partners may be taken without a meeting, without prior notice and without a vote, if an approval in writing setting forth the action so taken is signed by Limited Partners owning not less than the minimum percentage of the Outstanding Units (including Units owned or deemed owned by the General Partner and its Affiliates) that would be necessary to authorize or take such action at a meeting at which all the Limited Partners were present and voted (unless such provision conflicts with any rule, regulation, guideline or requirement of any National Securities Exchange on which the Limited Partner Interests are listed or admitted for trading, in which case the rule, regulation, guideline or requirement of such exchange shall govern). Prompt notice of the taking of action without a meeting shall be given to the Limited Partners who have not approved in writing. The General Partner may specify that any written ballot submitted to Limited Partners for the purpose of taking any action without a meeting shall be returned to the Partnership within the time period, which shall be not less than 20 days, specified by the General Partner. If a ballot returned to the Partnership does not vote all of the Units held by the Limited Partners, the Partnership shall be deemed to have failed to receive a ballot for the Units that were not voted. If approval of the taking of any action by the Limited Partners is solicited by any Person other than by or on behalf of the General Partner, the written approvals shall have no force and effect unless and until (a) they are deposited with the Partnership in care of the General Partner, (b) approvals sufficient to take the action proposed are dated as of a date not more than 90 days prior to the date sufficient approvals are deposited with the Partnership and (c) an Opinion of Counsel is delivered to the General Partner to the effect that the exercise of such right and the action proposed to be taken with respect to any particular matter (i) will not cause the Limited Partners to be deemed to be taking part in the management and control of the business and affairs of the Partnership so as to jeopardize the Limited Partners' limited liability, and (ii) is otherwise permissible under the state statutes then governing the rights, duties and liabilities of the Partnership and the Partners. Nothing contained in this Section 13.11 shall be deemed to require the General Partner to solicit all Limited Partners in connection with a matter approved by the holders of the requisite percentage of Units acting by written consent without a meeting.

SECTION 13.12. *Voting and Other Rights*

(a) Only those Record Holders of the Outstanding Units on the Record Date set pursuant to Section 13.6 (and also subject to the limitations contained in the definition of "*Outstanding*") shall be entitled to notice of, and to vote at, a meeting of Limited Partners or to act with respect to matters as to which the holders of the Outstanding Units have the right to vote or to act. All references in this Agreement to votes of, or other acts that may be taken by, the Outstanding Units shall be deemed to be references to the votes or acts of the Record Holders of such Outstanding Units.

(b) With respect to Units that are held for a Person's account by another Person (such as a broker, dealer, bank, trust company or clearing corporation, or an agent of any of the foregoing), in whose name such Units are registered, such other Person shall, in exercising the voting rights in respect of such Units on any matter, and unless the arrangement between such Persons provides otherwise, vote such Units in favor of, and at the direction of, the Person who is the beneficial owner, and the Partnership shall be entitled to assume it is so acting without further inquiry. The provisions of this Section 13.12(b) (as well as all other provisions of this Agreement) are subject to the provisions of Section 4.3.

ARTICLE XIV

MERGER, CONSOLIDATION OR CONVERSION

SECTION 14.1. *Authority*

The Partnership may merge or consolidate with or into one or more corporations, limited liability companies, statutory trusts or associations, real estate investment trusts, common law trusts or unincorporated businesses, including a partnership (whether general or limited (including a limited liability partnership)) or convert into any such entity, whether such entity is formed under the laws of the State of Delaware or any other state of the United States of America, pursuant to a written agreement or plan of merger or consolidation ("*Merger Agreement*") or a written plan of conversion ("*Plan of Conversion*"), as the case may be, in accordance with this Article XIV. It is expressly agreed that any merger or consolidation of any member of the Partnership Group (other than the Partnership) shall not be subject to the requirements of this Article XIV.

SECTION 14.2. *Procedure for Merger, Consolidation or Conversion*

(a) Merger, consolidation or conversion of the Partnership pursuant to this Article XIV requires the prior consent of the General Partner; *provided*, *however*, that, to the maximum extent permitted by law, the General Partner shall have no duty or obligation to consent to any merger, consolidation or conversion of the Partnership and may decline to do so free of any fiduciary duty or obligation whatsoever to the Partnership or any Limited Partner and, in declining to consent to a merger, consolidation or conversion, shall not be required to act in good faith or pursuant to any other standard imposed by this Agreement, any other agreement contemplated hereby or under the Delaware Act or any other law, rule or regulation or at equity.

(b) If the General Partner shall determine to consent to the merger or consolidation, the General Partner shall approve the Merger Agreement, which shall set forth:

(i) the names and jurisdictions of formation or organization of each of the business entities proposing to merge or consolidate;

(ii) the name and jurisdiction of formation or organization of the business entity that is to survive the proposed merger or consolidation (the "*Surviving Business Entity*");

(iii) the terms and conditions of the proposed merger or consolidation;

(iv) the manner and basis of exchanging or converting the equity securities of each constituent business entity for, or into, cash, property or interests, rights, securities or obligations of the Surviving Business Entity; and (i) if any general or limited partner interests, securities or rights of any constituent business entity are not to be exchanged or converted solely for, or into, cash, property or general or limited partner interests, rights, securities or obligations of the Surviving Business Entity, the cash, property or interests, rights, securities or obligations of any general or limited partnership, corporation, trust, limited liability company, unincorporated business or other entity (other than the Surviving Business Entity) which the holders of such general or limited partner interests, securities or rights are to receive in exchange for, or upon conversion of their interests, securities or rights, and (ii) in the case of securities represented by certificates, upon the surrender of such certificates, which cash, property or general or limited partner interests, rights, securities or obligations of the Surviving Business Entity or any general or limited partnership, corporation, trust, limited liability company, unincorporated business or other entity (other than the Surviving Business Entity), or evidences thereof, are to be delivered;

(v) a statement of any changes in the constituent documents or the adoption of new constituent documents (the articles or certificate of incorporation, articles of trust, declaration of trust, certificate or agreement of limited partnership, operating agreement or other similar charter or governing document) of the Surviving Business Entity to be effected by such merger or consolidation;

(vi) the effective time of the merger, which may be the date of the filing of the certificate of merger pursuant to Section 14.4 or a later date specified in or determinable in accordance with the Merger Agreement (*provided* that if the effective time of the merger is to be later than the date of the filing of such certificate of merger, the effective time shall be fixed at a date or time certain at or prior to the time of the filing of such certificate of merger and stated therein); and

(vii) such other provisions with respect to the proposed merger or consolidation that the General Partner determines to be necessary or appropriate.

(c) If the General Partner shall determine to consent to the conversion, the General Partner may approve and adopt a Plan of Conversion containing such terms and conditions that the General Partner determines to be necessary or appropriate.

SECTION 14.3. *Approval by Limited Partners*

(a) Except as provided in Section 14.3(d), the General Partner, upon its approval of the Merger Agreement or the Plan of Conversion, as the case may be, shall direct that the Merger Agreement or the Plan of Conversion, as applicable, be submitted to a vote of Limited Partners, whether at a special meeting or by written consent, in either case in accordance with the requirements of Article XIII. A copy or a summary of the Merger Agreement or the Plan of Conversion, as applicable, shall be included in or enclosed with the notice of a special meeting or the written consent.

(b) Except as provided in Section 14.3(d) and 14.3(e), the Merger Agreement or the Plan of Conversion, as applicable, shall be approved upon receiving the affirmative vote or consent of the holders of a Unit Majority, unless the Merger Agreement or Plan of Conversion, as the case may be, effects an amendment to any provision of this Agreement that, if contained in an amendment to this Agreement adopted pursuant to Article XIII, would require for its approval the vote or consent of a greater percentage of the Outstanding Units or of any class of Limited Partners, in which case such greater percentage vote or consent shall be required for approval of the Merger Agreement or the Plan of Conversion, as the case may be.

(c) Except as provided in Section 14.3(d) and 14.3(e), after such approval by vote or consent of the Limited Partners, and at any time prior to the filing of the certificate of merger or the certificate of conversion pursuant to Section 14.4, the merger, consolidation or conversion may be abandoned pursuant to provisions therefor, if any, set forth in the Merger Agreement or the Plan of Conversion, as the case may be.

(d) Notwithstanding anything else contained in this Article XIV or in this Agreement, the General Partner is permitted, without Limited Partner approval, to convert the Partnership or any Group Member into a new limited liability entity, to merge the Partnership or any Group Member into, or convey all of the Partnership's assets to, another limited liability entity that shall be newly formed and shall have no assets, liabilities or operations at the time of such conversion, merger or conveyance other than those it receives from the Partnership or other Group Member if (i) the General Partner has received an Opinion of Counsel that the conversion, merger or conveyance, as the case may be, would not result in the loss of the limited liability of any Limited Partner as compared to its limited liability under the Delaware Act or cause the Partnership to be treated as an association taxable as a corporation or otherwise to be taxed as an entity for U.S. federal income tax purposes (to the extent not previously treated as such), (ii) the purpose of such conversion, merger or conveyance is to effect a change in the legal form of the Partnership into another limited liability entity and (iii) the General Partner determines that the governing instruments of the new entity provide the Limited Partners and the General Partner with substantially the same rights and obligations as are herein contained.

(e) Additionally, notwithstanding anything else contained in this Article XIV or in this Agreement, the General Partner is permitted, without Limited Partner approval, to merge or consolidate the Partnership with or into another entity if (i) the General Partner has received an Opinion of Counsel that the merger or consolidation, as the case may be, would not result in the loss of the limited liability of any Limited Partner as compared to its limited liability under the Delaware Act or cause the Partnership to be treated as an association taxable as a corporation or otherwise to be taxed as an entity for U.S. federal income tax purposes (to the extent not previously treated as such), (ii) the merger or consolidation would not result in an amendment to this Agreement, other than any amendments that could be adopted pursuant to Section 13.1, (iii) the Partnership is the Surviving Business Entity in such merger or consolidation, (iv) each Unit Outstanding immediately prior to the effective date of the merger or consolidation is to be an identical Unit of the Partnership after the effective date of the merger or consolidation and (v) the number of Partnership Interests to be issued by the Partnership in such merger or consolidation does not exceed 20% of the Partnership Interests (other than Incentive Distribution Rights) Outstanding immediately prior to the effective date of such merger or consolidation.

SECTION 14.4. *Certificate of Merger or Conversion*

Upon the required approval, if any, by the General Partner and the Unitholders of a Merger Agreement or a Plan of Conversion, as the case may be, a certificate of merger or certificate of conversion, as applicable, shall be executed and filed with the Secretary of State of the State of Delaware in conformity with the requirements of the Delaware Act.

SECTION 14.5. *Effect of Merger, Consolidation or Conversion*

(a) At the effective time of the merger:

(i) all of the rights, privileges and powers of each of the business entities that has merged or consolidated, and all property, real, personal and mixed, and all debts due to any of those business entities and all other things and causes of action belonging to each of those business entities, shall be vested in the Surviving Business Entity and after the merger or consolidation shall be the property of the Surviving Business Entity to the extent they were of each constituent business entity;

(ii) the title to any real property vested by deed or otherwise in any of those constituent business entities shall not revert and is not in any way impaired because of the merger or consolidation;

(iii) all rights of creditors and all liens on or security interests in property of any of those constituent business entities shall be preserved unimpaired; and

(iv) all debts, liabilities and duties of those constituent business entities shall attach to the Surviving Business Entity and may be enforced against it to the same extent as if the debts, liabilities and duties had been incurred or contracted by it.

(b) At the effective time of the conversion:

(i) the Partnership shall continue to exist, without interruption, but in the organizational form of the converted entity rather than in its prior organizational form;

(ii) all rights, title, and interests to all real estate and other property owned by the Partnership shall continue to be owned by the converted entity in its new organizational form without reversion or impairment, without further act or deed, and without any transfer or assignment having occurred, but subject to any existing liens or other encumbrances thereon;

(iii) all liabilities and obligations of the Partnership shall continue to be liabilities and obligations of the converted entity in its new organizational form without impairment or diminution by reason of the conversion;

(iv) all rights of creditors or other parties with respect to or against the prior interest holders or other owners of the Partnership in their capacities as such in existence as of the effective time of the conversion will continue in existence as to those liabilities and obligations and may be pursued by such creditors and obligees as if the conversion did not occur;

(v) a proceeding pending by or against the Partnership or by or against any of Partners in their capacities as such may be continued by or against the converted entity in its new organizational form and by or against the prior partners without any need for substitution of parties; and

(vi) the Partnership Interests that are to be converted into partnership interests, shares, evidences of ownership or other securities in the converted entity as provided in the Plan of Conversion or certificate of conversion shall be so converted, and Partners shall be entitled only to the rights provided in the Plan of Conversion or certificate of conversion.

(c) A merger, consolidation or conversion effected pursuant to this Article XIV shall not be deemed to result in a transfer or assignment of assets or liabilities from one entity to another.

SECTION 14.6. *Amendment of Partnership Agreement*.

Pursuant to Section 17-211(g) of the Delaware Act, an agreement or plan of merger or consolidation approved in accordance with Section 17-211(b) of the Delaware Act may (a) effect any amendment to this Agreement or (b) effect the adoption of a new partnership agreement for a limited partnership if it is the Surviving Business Entity. Any such amendment or adoption made pursuant to this Article XIV shall be effective at the effective time or date of the merger or consolidation.

ARTICLE XV

RIGHT TO ACQUIRE LIMITED PARTNER INTERESTS

SECTION 15.1. *Right to Acquire Limited Partner Interests*

(a) Notwithstanding any other provision of this Agreement, if at any time the General Partner and its Affiliates hold more than two-thirds of the total Limited Partner Interests of any class then Outstanding, the General Partner shall then have the right, which right it may assign and transfer in whole or in part to the Partnership or any Affiliate of the General Partner, exercisable in its sole discretion, to purchase all, but not less than all, of such Limited Partner Interests of such class then Outstanding held by Persons other than the General Partner and its Affiliates, at the greater of (x) the Current Market Price as of the date three days prior to the date that the notice described in Section 15.1(b) is mailed and (y) the highest price paid by the General Partner or any of its Affiliates for any such Limited Partner Interest of such class purchased during the 90-day period preceding the date that the notice described in Section 15.1(b) is mailed. As used in this Agreement, (i) "*Current Market Price*" as of any date of any class of Limited Partner Interests means the average of the daily Closing Prices (as hereinafter defined) per Limited Partner Interest of such class for the 20 consecutive Trading Days (as hereinafter defined) immediately prior to such date; (ii) "*Closing Price*" for any day means the last sale price on such day, regular way, or in case no such sale takes place on such day, the average of the closing bid and asked prices on such day, regular way, in either case as reported in the principal consolidated transaction reporting system with respect to securities listed or admitted for trading on the principal National Securities Exchange on which such Limited Partner Interests of such class are listed or admitted to trading or, if such Limited Partner Interests of such class are not listed or admitted for trading on any National Securities Exchange, the last quoted price on such day or, if not so quoted, the average of the high bid and low asked prices on such day in the over-the-counter market, as reported by the primary reporting system then in use in relation to such Limited Partner Interest of such class, or, if on any such day such Limited Partner Interests of such class are not quoted by any such organization, the average of the closing bid and asked prices on such day as furnished by a professional market maker making a market in such Limited Partner Interests of such class selected by the General Partner, or if on any such day no market maker is making a market in such Limited Partner Interests of such class, the fair value of such Limited Partner Interests on such day as determined by the General Partner; and (iii) "*Trading Day*" means a day on which the principal National Securities Exchange on which such Limited Partner Interests of any class are listed or admitted for trading is open for the transaction of business or, if Limited Partner Interests of a class are not listed or admitted for trading on any National Securities Exchange, a day on which banking institutions in New York City generally are open.

(b) If the General Partner, any Affiliate of the General Partner or the Partnership elects to exercise the right to purchase Limited Partner Interests granted pursuant to Section 15.1(a), the General Partner shall deliver to the Transfer Agent notice of such election to purchase (the "*Notice of Election to Purchase*") and shall cause the Transfer Agent to mail a copy of such Notice of Election to Purchase to the Record Holders of Limited Partner Interests of such class (as of a Record Date selected by the General Partner) at least 10, but not more than 60, days prior to the Purchase Date. Such Notice of Election to Purchase shall also be published for a period of at least three consecutive days in at least two daily newspapers of general circulation printed in the English language and published in the Borough of Manhattan, New York. The Notice of Election to Purchase shall specify the Purchase Date and the price (determined in accordance with Section 15.1(a)) at which Limited Partner Interests will be purchased and state that the General Partner, its Affiliate or the Partnership, as the case may be, elects to purchase such Limited Partner Interests, upon surrender of Certificates representing such Limited Partner Interests in the case of Limited Partner Interests evidenced by Certificates, in exchange for payment, at such office or offices of the Transfer Agent as the Transfer Agent may specify, or as may be required by any National Securities Exchange on which such Limited Partner Interests are listed or admitted for trading. Any such Notice of Election to Purchase mailed to a Record Holder of Limited Partner Interests at his address as reflected in the records of the Transfer Agent shall be conclusively presumed to have been given regardless of whether the owner receives such notice. On or prior to the Purchase Date, the General Partner, its Affiliate or the Partnership, as the case may be, shall deposit with the Transfer Agent cash in an amount sufficient to pay the aggregate purchase price of all of such Limited Partner Interests to be purchased in accordance with this Section 15.1. If the Notice of Election to Purchase shall have been duly given as aforesaid at least 10 days prior to the Purchase Date, and if on or prior to the Purchase Date the deposit described in the preceding sentence has been made for the benefit of the holders of Limited Partner Interests subject to purchase as provided herein, then from and after the Purchase Date, notwithstanding that any Certificate shall not have been surrendered for purchase, all rights of the holders of such Limited Partner Interests (including any rights pursuant to Articles IV, V, VI, and XII) shall thereupon cease, except the right to receive the purchase price (determined in accordance with Section 15.1(a)) for their Limited Partner Interests, without interest, upon surrender to the Transfer Agent of the Certificates representing such Limited Partner Interests (in the case of Limited Partner Interests evidenced by Certificates), and such Limited Partner Interests shall thereupon be deemed to be transferred to the General Partner, its Affiliate or the Partnership, as the case may be, on the record books of the Transfer Agent and the Partnership, and the General Partner, its Affiliate or the Partnership, as the case may be, shall be deemed to be the owner of all such Limited Partner Interests from and after the Purchase Date and shall have all rights as the owner of such Limited Partner Interests (including all rights as owner of such Limited Partner Interests pursuant to Articles IV, V, VI, and XII).

(c) In the case of Limited Partner Interests evidenced by Certificates, at any time from and after the Purchase Date, a holder of an Outstanding Limited Partner Interest subject to purchase as provided in this Section 15.1 may surrender his Certificate evidencing such Limited Partner Interest to the Transfer Agent in exchange for payment of the amount described in Section 15.1(a), therefor, without interest thereon.

ARTICLE XVI

GENERAL PROVISIONS

SECTION 16.1. *Addresses and Notices; Written Communications*

Any notice, demand, request, report or proxy materials required or permitted to be given or made to a Partner under this Agreement shall be in writing and shall be deemed given or made when delivered in person or when sent by first class United States mail or by other means of written communication to the Partner at the address described below. Any notice, payment or report to be given or made to a Partner hereunder shall be deemed conclusively to have been given or made, and the obligation to give such notice or report or to make such payment shall be deemed conclusively to have been fully satisfied, upon sending of such notice, payment or report to the Record Holder of such Partnership Interests at his address as shown on the records of the Transfer Agent or as otherwise shown on the records of the Partnership, regardless of any claim of any Person who may have an interest in such Partnership Interests by reason of any assignment or otherwise. Notwithstanding the foregoing, if (i) a Partner shall consent to receiving notices, demands, requests, reports or proxy materials via electronic mail or by the Internet or (ii) the rules of the Commission shall permit any report or proxy materials to be delivered electronically or made available via the Internet, any such notice, demand, request, report or proxy materials shall be deemed given or made when delivered or made available via such mode of delivery. An affidavit or certificate of making of any notice, payment or report in accordance with the provisions of this Section 16.1 executed by the General Partner, the Transfer Agent or the mailing organization shall be *prima facie* evidence of the giving or making of such notice, payment or report. If any notice, payment or report addressed to a Record Holder at the address of such Record Holder appearing on the books and records of the Transfer Agent or the Partnership is returned by the United States Postal Service marked to indicate that the United States Postal Service is unable to deliver it, such notice, payment or report and any subsequent notices, payments and reports shall be deemed to have been duly given or made without further mailing (until such time as such Record Holder or another Person notifies the Transfer Agent or the Partnership of a change in his address) if they are available for the Partner at the principal office of the Partnership for a period of one year from the date of the giving or making of such notice, payment or report to the other Partners. Any notice to the Partnership shall be deemed given if received by the General Partner at the principal office of the Partnership designated pursuant to Section 2.3. The General Partner may rely and shall be protected in relying on any notice or other document from a Partner or other Person if believed by it to be genuine. The terms "in writing," "written communications," "written notice" and words of similar import shall be deemed satisfied under this Agreement by use of e-mail and other forms of electronic communication.

SECTION 16.2. *Further Action*

The parties shall execute and deliver all documents, provide all information and take or refrain from taking action as may be necessary or appropriate to achieve the purposes of this Agreement.

SECTION 16.3. *Binding Effect*

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their heirs, executors, administrators, successors, legal representatives and permitted assigns.

SECTION 16.4. *Integration*

This Agreement constitutes the entire agreement among the parties hereto pertaining to the subject matter hereof and supersedes all prior agreements and understandings pertaining thereto.

SECTION 16.5. *Creditors*

None of the provisions of this Agreement shall be for the benefit of, or shall be enforceable by, any creditor of the Partnership.

SECTION 16.6. *Waiver*

No failure by any party to insist upon the strict performance of any covenant, duty, agreement or condition of this Agreement or to exercise any right or remedy consequent upon a breach thereof shall constitute waiver of any such breach of any other covenant, duty, agreement or condition.

SECTION 16.7. *Third-Party Beneficiaries*

Each Partner agrees that (a) any Indemnitee shall be entitled to assert rights and remedies hereunder as a third-party beneficiary hereto with respect to those provisions of this Agreement affording a right, benefit or privilege to such Indemnitee and (b) any Unrestricted Person shall be entitled to assert rights and remedies hereunder as a third-party beneficiary hereto with respect to those provisions of this Agreement affording a right, benefit or privilege to such Unrestricted Person.

SECTION 16.8. *Counterparts*

This Agreement may be executed in counterparts, all of which together shall constitute an agreement binding on all the parties hereto, notwithstanding that all such parties are not signatories to the original or the same counterpart. Each party shall become bound by this Agreement immediately upon affixing its signature hereto or, in the case of a Person acquiring a Limited Partner Interest pursuant to Section 10.1(a), without execution hereof.

SECTION 16.9. *Applicable Law; Forum; Venue and Jurisdiction*

(a) This Agreement shall be construed in accordance with and governed by the laws of the State of Delaware, without regard to the principles of conflicts of law.

(b) Each of the Partners and each Person holding any beneficial interest in the Partnership (whether through a broker, dealer, bank, trust company or clearing corporation or an agent of any of the foregoing or otherwise):

(i) irrevocably agrees that, unless the Partnership (through the approval of the General Partner) consents in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall be the sole and exclusive forum for any claims, suits, actions or proceedings (A) arising out of or relating in any way to this Agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of this Agreement or the duties, obligations or liabilities among Partners or of Partners to the Partnership, or the rights or powers of, or restrictions on, the Partners or the Partnership), (B) brought in a derivative manner on behalf of the Partnership, (C) asserting a claim of breach of a duty owed by any director, officer or other employee of the Partnership or the General Partner or any Indemnitee, or owed by the General Partner, to the Partnership or the Partners, (D) asserting a claim arising pursuant to any provision of the Delaware Act or (E) asserting a claim governed by the internal affairs doctrine, in each case regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims; *provided* that if and only if the Court of Chancery of the Statement of Delaware dismisses any such claims, suits, actions or proceedings for lack of subject matter jurisdiction, such claims, suits, actions or proceedings may be brought in another state or federal court sitting in the State of Delaware;

(ii) irrevocably submits, unless the Partnership (through the approval of the General Partner) consents in writing to the selection of an alternative forum, to the exclusive jurisdiction of the Court of Chancery of the State of Delaware in connection with any such claim, suit, action or proceeding; *provided* that if and only if the Court of Chancery of the Statement of Delaware dismisses any such claims, suits, actions or proceedings for lack of subject matter jurisdiction, it irrevocably submits to the exclusive jurisdiction of any state or federal court sitting in the State of Delaware;

(iii) irrevocably agrees not to, and irrevocably waives any right to, assert in any such claim, suit, action or proceeding that (A) it is not personally subject to the jurisdiction of the Court of Chancery of the State of Delaware (unless the Partnership (through the approval of the General Partner) consents in writing to the selection of an alternative forum) or of any other court to which proceedings in the Court of Chancery of the State of Delaware may be appealed (unless the Partnership (through the approval of the General Partner) consents in writing to the selection of an alternative forum); provided that if and only if the Court of Chancery of the Statement of Delaware dismisses any such claims, suits, actions or proceedings for lack of subject matter jurisdiction, then it irrevocably agrees not to, and irrevocably waives any right to, assert in any such claim, suit, action or proceeding that (A) it is not personally subject to the jurisdiction of any state or federal court sitting in the State of Delaware, (B) such claim, suit, action or proceeding is brought in an inconvenient forum, or (C) the venue of such claim, suit, action or proceeding is improper;

(iv) expressly waives any requirement for the posting of a bond by a party bringing such claim, suit, action or proceeding; and

(v) consents to process being served in any such claim, suit, action or proceeding by mailing, certified mail, return receipt requested, a copy thereof to such party at the address in effect for notices hereunder, and agrees that such services shall constitute good and sufficient service of process and notice thereof; *provided*, nothing in clause (v) hereof shall affect or limit any right to serve process in any other manner permitted by law.

SECTION 16.10. *Invalidity of Provisions*

If any provision or part of a provision of this Agreement is or becomes for any reason, invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions and/or parts thereof contained herein shall not be affected thereby and this Agreement shall, to the fullest extent permitted by law, be reformed and construed as if such invalid, illegal or unenforceable provision, or part of a provision, had never been contained herein, and such provisions and/or part shall be reformed so that it would be valid, legal and enforceable to the maximum extent possible.

SECTION 16.11. *Consent of Partners*

Each Partner hereby expressly consents and agrees that, whenever in this Agreement it is specified that an action may be taken upon the affirmative vote or consent of less than all of the Partners, such action may be so taken upon the concurrence of less than all of the Partners and each Partner shall be bound by the results of such action.

SECTION 16.12. *Facsimile and PDF Signatures*

The use of facsimile signatures and signatures delivered by email in portable document format (.pdf) affixed in the name and on behalf of the transfer agent and registrar of the Partnership on certificates representing Common Units is expressly permitted by this Agreement.

[Signature page follows]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

GENERAL PARTNER:

ATLAS RESOURCE PARTNERS GP, LLC

By: Atlas Energy, L.P., its Sole Member

By: Atlas Energy GP, LLC, its General Partner

By: ____________________________________
Name:
Title:

ORGANIZATIONAL LIMITED PARTNER:

ATLAS ENERGY, L.P.

By: Atlas Energy GP, LLC, its General Partner

By: ____________________________________
Name:
Title: