ATLAS PIPELINE PARTNERS LP
Form 10-K
March 05, 2010

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

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

For the transition period from ______ to ______

Commission file number: 1-14998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1550 Coraopolis Heights Road	
Moon Township, Pennsylvania	**15108**
(Address of principal executive office)	**(Zip code)**

Registrant s telephone number, including area code: (412) 262-2830

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

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

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

None

(Title of class)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

The aggregate market value of the equity securities held by non-affiliates of the registrant, based upon the closing price of $7.96 per common limited partner unit on June 30, 2009, was approximately $324.6 million.

The number of common units of the registrant outstanding on March 2, 2010 was 53,207,459.

DOCUMENTS INCORPORATED BY REFERENCE: None

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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FORWARD-LOOKING STATEMENTS

The matters discussed within this report include forward-looking statements. These statements may be identified by the use of forward-looking terminology such as anticipate, believe, continue, could, estimate, expect, intend, may, might, plan, potential, predict, should, or will, or the negative thereof or other variations thereon or comparable terminology. In particular, statements about our expectations, beliefs, plans, objectives, assumptions or future events or performance contained in this report are forward-looking statements. We have based these forward-looking statements on our current expectations, assumptions, estimates and projections. While we believe these expectations, assumptions, estimates and projections are reasonable, such forward-looking statements are only predictions and involve known and unknown risks and uncertainties, many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. Some of the key factors that could cause actual results to differ from our expectations include:

- *the demand for natural gas and natural gas liquids;*
- *the price volatility of natural gas and natural gas liquids;*
- *our ability to connect new wells to our gathering systems;*
- *adverse effects of governmental and environmental regulation;*
- *limitations on our access to capital or on the market for our common units; and*
- *the strength and financial resources of our competitors.*

Other factors that could cause actual results to differ from those implied by the forward-looking statements in this report are more fully described under Item 1A, Risk Factors in this report. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

Glossary of Terms

Definitions of terms and acronyms generally used in the energy industry and in this report are as follows:

BPD	Barrels per day. Measurement for standard US barrel is 42 gallons
BTU	British thermal unit
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
Fractionation	The process used to separate an NGL stream into its individual components.
Keep-Whole	Contract with producer whereby plant operator pays for or returns an equivalent BTU of the gas gathered at the well-head.
MCF	Thousand cubic feet
MCFD	Thousand cubic feet per day
MMBTU	Million British thermal units
MMCFD	Million cubic feet per day
NGL(s)	Natural Gas Liquid(s), primarily ethane, propane, normal butane, isobutane and natural gasoline

Percentage of Proceeds	(POP) Contract with Natural Gas Producers whereby the plant operator retains a negotiated percentage of the sale proceeds.
Residue Gas	The portion of natural gas remaining after natural gas is processed for removal of NGLs and impurities.
Y-grade	A term utilized in the industry for the NGL stream prior to fractionation, also referred to as raw mix.

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PART I

ITEM 1. BUSINESS

General

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. Our principal business objective is to generate cash for distribution to our unitholders. We are a leading provider of natural gas gathering services in the Anadarko and Permian Basins located in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing and treating services in Oklahoma and Texas.

Our general partner, Atlas Pipeline Partners GP, LLC (Atlas Pipeline GP or the General Partner), manages our operations and activities through its ownership of our general partner interest. Atlas Pipeline GP is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (Atlas Pipeline Holdings or AHD), a publicly traded Delaware limited partnership (NYSE: AHD) which owned an 11.2% limited partner interest in us, as well as the 2% general partner interest, at December 31, 2009.

Atlas Energy, Inc. (Atlas Energy), a publicly-traded company (NASDAQ: ATLS), owned 64.3% of the common units of AHD at December 31, 2009. Atlas Energy also had a direct 2.2% ownership interest in us at December 31, 2009.

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Mid-Continent and Appalachia.

In our Mid-Continent operations, we own, have interests in and operate eight natural gas processing plants with aggregate capacity of approximately 900 MMCFD and one treating facility with a capacity of approximately 200 MMCFD. These facilities are connected to approximately 9,100 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas, which gathers gas from wells and central delivery points to our natural gas processing and treating plants, as well as third-party pipelines.

Our Appalachia operations are conducted principally through our 49% ownership interest in the Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), which owns and operates approximately 1,800 miles of natural gas gathering systems in the Appalachian Basin located in the northeastern United States. We also own and operate approximately 80 miles of active natural gas gathering pipelines located in northeastern Tennessee.

On May 31, 2009, we and subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) completed the formation of Laurel Mountain, which currently owns and operates our former Appalachia natural gas gathering system (Legacy Appalachia), excluding our northeastern Tennessee operations. Laurel Mountain gathers the majority of the natural gas from wells operated by Atlas Energy Resources, LLC and its subsidiaries (Atlas Energy Resources), a wholly owned subsidiary of Atlas Energy. Laurel Mountain has gas gathering agreements with Atlas Energy Resources under which Atlas Energy Resources is obligated to pay a gathering fee that is generally the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations).

Since our initial public offering in January 2000, we have completed seven acquisitions at an aggregate purchase price of approximately $2.4 billion, including most recently, in July 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas

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gathering systems and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). At the date of acquisition, the Chaney Dell system included 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum system included 2,500 miles of gathering pipeline and two processing plants. The transaction was accomplished through the formation of two joint venture companies which own the respective systems, to which we contributed $1.9 billion and Anadarko contributed the Anadarko Assets. We funded the purchase price with a private placement of common units and from a senior secured term loan and a senior secured revolving credit facility. Our General Partner, which holds all of our incentive distribution rights, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. Our General Partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the General Partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter (the IDR Adjustment Agreement). In connection with this acquisition, we reached an agreement with Pioneer Natural Resources Company (Pioneer NYSE: PXD), which holds an approximate 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer had options to buy up to an additional 22% interest in the Midkiff/Benedum system. These options expired on November 2, 2009.

Our operations are all located in or near areas of abundant and long-lived natural gas production including the Granite Wash formation; Golden Trend; Woodford Shale; Hugoton field in the Anadarko basin; the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin and the Marcellus Shale in the Appalachian Basin. In the Mid-Continent, our gathering systems are connected to approximately 7,900 central delivery points or wells. In Appalachia, Laurel Mountain s systems are connected to approximately 7,700 wells. Thus, we believe that we have significant scale in our service areas. We provide gathering and processing services to the wells connected to our systems, primarily under long-term contracts. As a result of the location and capacity of our gathering and processing assets, we believe we are strategically positioned to capitalize on the drilling activity in our service areas. We intend to continue to expand our business through strategic acquisitions and internal growth projects in efforts to increase distributable cash flow.

The Midstream Natural Gas Gathering and Processing Industry

The midstream natural gas gathering and processing industry is characterized by regional competition based on the proximity of gathering systems and processing plants to producing natural gas wells.

The natural gas gathering process begins with the drilling of wells into natural gas or oil bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of pipelines that collect natural gas from points near producing wells and transport gas and other associated products to larger pipelines for further transportation to end-user markets. Gathering systems are operated at design pressures via pipe size and compression that will maximize the total throughput from all connected wells.

While natural gas produced in some areas, such as certain regions of the Appalachian Basin, does not require treatment or processing, natural gas produced in many other areas, such as our Midkiff/Benedum and our Velma operations in the Mid-Continent, are not suitable for long-haul pipeline transportation or commercial use and must be compressed, gathered via pipeline to a central processing facility, potentially treated and then processed to remove certain hydrocarbon components such as NGLs and other contaminants that would interfere with pipeline transportation or the end use of the natural gas. Natural gas processing plants generally treat (remove carbon dioxide and hydrogen sulfide) and extract the NGLs, enabling the treated, dry gas (low BTU content) to meet pipeline specification for long-haul transport to end users. After being separated from natural gas at the processing plant, the mixed NGL stream, commonly referred to as y-grade or raw mix, is typically transported in pipelines to a centralized facility for fractionation into discrete NGL purity products: ethane, propane, normal butane, isobutane, and natural gasoline.

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Natural gas transportation pipelines receive natural gas from producers, other mainline transportation pipelines, shippers and gathering systems through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial end-users, utilities and other pipelines. Generally natural gas transportation agreements generate revenue for these systems based on a fee per unit of volume transported.

Business Strategy

The primary business objective of our management team is to provide stable long-term cash distributions to our unitholders. Our business strategies focus on creating value for our unitholders by providing efficient operations, focusing on prudent growth opportunities via organic growth projects and external acquisitions, and maintaining a commodity risk management program in an attempt to manage our commodity price exposure. We intend to accomplish our primary business objectives by executing on the following:

- *Increasing the profitability of our existing assets*. In many cases, our gathering pipelines and processing plants have excess capacity, which provides us with opportunities to connect and process new supplies of natural gas with minimal additional capital requirements. We plan to accomplish this goal by providing excellent service to our existing customers, aggressively marketing our services to new customers and prudently expanding our existing infrastructure to ensure our services can meet the needs of potential customers. Our recent construction of the Consolidator Plant in West Texas is an example of executing this strategy. Other opportunities include pursuing the elimination of pipeline bottlenecks, reducing operating line pressures and focusing on a reduction of pipeline losses along our gathering systems.

- *Expanding operations through organic growth projects and pursuing strategic acquisitions*. We continue to explore opportunities to expand our existing infrastructure. We also plan to pursue strategic acquisitions that are accretive to our unitholders, by seeking acquisition opportunities that leverage our existing asset base, employees and existing customer relationships. In the past, we have pursued opportunities in certain regions outside of our current areas of operation and will continue to do so when these options make sense economically and strategically.

- *Reducing the sensitivity of our cash flows through prudent economic hedging arrangements*. We attempt to structure our contracts in a manner that allows us to achieve our target rate of return goals while reducing our exposure to commodity price movements. Our commodity risk management activities are designed to reduce the effect of commodity price volatility related to future sales of natural gas, NGLs and crude oil, while allowing us to meet our debt service requirements, fund our maintenance capital program and meet our distribution objectives.

Contracts and Customer Relationships

Our principal revenue is generated from the gathering and sale of natural gas and NGLs. Primary contracts are Fee-Based, Percentage of Proceeds (POP) and Keep-Whole (see Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Revenue Arrangements).

Our Mid-Continent Operations

We own and operate approximately 9,100 miles of intrastate natural gas gathering systems located in Oklahoma, Kansas, and Texas. We also own and operate eight processing plants and one stand-alone treating facility located in Oklahoma and Texas. Our gathering, processing and treating assets service long-lived natural gas regions, including the Permian and Anadarko Basins. Our systems gather natural gas from oil and natural gas wells and process the raw natural gas into merchantable, or residue, gas by extracting NGLs and removing impurities. In the aggregate, our Mid-Continent systems have approximately 7,900 receipt points, consisting primarily of individual well connections and, secondarily, central delivery points which are linked to multiple wells. Our gathering systems interconnect with interstate and intrastate pipelines operated by ANR Pipeline Company, CenterPoint Energy, Inc., El Paso Natural Gas Company, Enogex LLC, Kinder Morgan Texas Pipeline, Natural Gas Pipeline Company of America, Northern Natural Gas Company, ONEOK Gas Transportation, LLC, Panhandle Eastern Pipe Line Company, LP and Southern Star Central Gas Pipeline, Inc. Our processing facilities are connected to NGL pipelines operated by ONEOK Hydrocarbon, L.P.

Mid-Continent Overview

We consider the Mid-Continent region as running from Kansas through Oklahoma, branching into northern and western Texas, as well as southeastern New Mexico. The primary producing areas in the region include the Anadarko Basin and the Permian Basin.

Mid-Continent Gathering Systems

Chaney Dell. The Chaney Dell gathering system is located in north central Oklahoma and southern Kansas Anadarko Basin. As of December 31, 2009, the gathering systems had approximately 4,100 miles of active natural gas gathering pipelines with approximately 3,700 receipt points.

Elk City/Sweetwater. The Elk City and Sweetwater gathering system includes approximately 800 miles of active natural gas pipelines located in the Anadarko Basin in western Oklahoma and the Texas panhandle, which encompasses the Atoka Wash and Granite Wash formations. The Elk City and Sweetwater gathering system connects to approximately 700 receipt points, with a majority of the system s western end located in areas of active drilling.

Midkiff/Benedum. The Midkiff/Benedum gathering system, which we operate and in which we have an approximate 72.8% ownership as of December 31, 2009, consists of approximately 3,000 miles of active natural gas gathering pipelines and approximately 2,800 receipt points located across four counties within the Permian Basin in West Texas. Pioneer, the largest active driller in the Spraberry Trend and a major producer in the Permian Basin, owns the remaining interest in the Midkiff/Benedum system.

Velma. The Velma gathering system is located in the Golden Trend and near the Woodford Shale areas of southern Oklahoma. As of December 31, 2009, the gathering system had approximately 1,200 miles of active pipelines with approximately 700 receipt points consisting primarily of individual well connections and, secondarily, central delivery points which are linked to multiple wells.

Mid-Continent Processing and Treating Plants

Chaney Dell. The Chaney Dell system processes natural gas through the Waynoka and Chester plants, which are active cryogenic natural gas processing facilities. The Chaney Dell system s processing operations have total capacity of approximately 228 MMCFD. The Waynoka processing plant, located in Woods County, Oklahoma began operations in December 2006 and became fully operational in July 2007. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the Waynoka and Chester plants and sell NGL production to ONEOK Hydrocarbon, L.P.

Elk City/Sweetwater. The Elk City, Sweetwater, Nine-Mile and Prentiss facilities are located on the Elk City/Sweetwater gathering system. The Elk City processing plant, located in Beckham County, Oklahoma, is a cryogenic natural gas processing plant with a total capacity of approximately 130 MMCFD. The Prentiss treating facility, also located in Beckham County, Oklahoma, is an amine treating facility with a total capacity of approximately 200 MMCFD. The Sweetwater processing plant, which began operations in September 2006, is a cryogenic natural gas processing plant located in Beckham County, Oklahoma. The Sweetwater plant had an initial capacity of approximately 120 MMCFD. We built the Sweetwater plant to further access natural gas production being actively developed in western Oklahoma and the Texas panhandle. During July 2008, we completed a 60 MMCFD expansion of the Sweetwater plant, bringing its total processing capacity to 180 MMCFD. We subsequently sold this 60 MMCFD additional plant capacity to Penn Virginia Resources in 2009. Thus, we now own and operate 120 MMCFD of capacity at the Sweetwater plant, but continue to operate the entire Sweetwater plant. The Nine-Mile plant is a newly constructed cryogenic natural gas plant. It has a capacity of 120 MMCFD, began operations in mid-2009 and is located in Dewey County, Oklahoma. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of our Elk City/Sweetwater plants, as well as sell NGL production to ONEOK Hydrocarbon, L.P.

Midkiff/Benedum. The Midkiff/Benedum system processes natural gas through the Consolidator and Benedum processing plants. The Consolidator plant is a 150 MMCFD cryogenic facility in Reagan County, Texas. The facility was started in November 2009 and replaced the Midkiff plant. The Benedum plant is a 43 MMCFD cryogenic facility in Upton County, Texas. Our Consolidator/Benedum processing operations have an aggregate processing capacity of approximately 193 MMCFD. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the Consolidator/Benedum plants and sell NGL production to ONEOK Hydrocarbon, L.P.

Velma. The Velma processing plant, located in Stephens County, Oklahoma, is a cryogenic facility with a natural gas capacity of approximately 100 MMCFD. The Velma plant is one of only two facilities in the area that is capable of treating both high-content hydrogen sulfide and carbon dioxide gases which are characteristic in this area. We have made capital expenditures at the facility to improve its efficiency and competitiveness, including installing electric-powered compressors rather than higher-cost natural gas-powered compressors used by many of our competitors. We transport and sell natural gas to parties, including various marketing companies and pipelines, at the tailgate of the Velma plant and sell NGL production to ONEOK Hydrocarbon, L.P.

Natural Gas Supply

In the Mid-Continent, we have natural gas purchase, gathering and/or processing agreements with approximately 550 producers with terms ranging from one month to 15 years. These agreements provide for the purchase or gathering of natural gas under Fee-Based, POP or Keep-Whole arrangements. Many of the agreements provide for compression, treating, processing and/or low volume fees. Producers generally provide, in-kind, their proportionate share of compressor and plant fuel required to gather the natural gas and to operate our processing plants. In addition, the producers generally bear their proportionate share of gathering system line loss and, except for Keep-Whole arrangements, bear natural gas plant shrinkage for the gas consumed in the production of NGLs.

We have long-term relationships with several of our Mid-Continent producers. For instance, we have producer relationships going back over 20 years on our Velma System. Several of our top producers, which accounted for a significant portion of our Velma volumes for the year ended December 31, 2009, have contracts with primary terms running well into 2013 and beyond. At the end of the primary terms, most of the contracts with producers on our gathering systems have evergreen term extensions. When we acquired control of the Midkiff/Benedum system in July 2007, we and Pioneer agreed to extend the existing gas sales and purchase agreement to 2022. The gas sales and purchase agreement requires that all Pioneer wells within an area of mutual interest be dedicated to that system s gathering and processing operations in return for specified natural gas processing rates. Through this agreement, we anticipate that we will continue to provide gathering and processing for the majority of Pioneer s wells in the Spraberry Trend of the Permian Basin.

Natural Gas and NGL Marketing

We typically sell natural gas to purchasers downstream of our processing plants priced at various first-of-month indices as published in *Inside FERC*. Additionally, swing gas, which is natural gas that is sold during the current month, is sold daily at various *Platt s Gas Daily* midpoint pricing points. The Velma plant has access to ONEOK Gas Transportation, LLC, an intrastate pipeline; and Southern Star Central Gas Pipeline, Inc.

and Natural Gas Pipeline Company of America, interstate pipelines. The Elk City/Sweetwater/Nine-Mile plants have access to six major interstate and intrastate downstream pipelines: Natural Gas Pipeline Company of America, Panhandle Eastern Pipe Line Company, LP, CenterPoint Energy, Inc., Northern Natural Gas Company, ANR Pipeline Company and ONEOK Gas Transportation, LLC. The Chester plant has access to Panhandle Eastern Pipe Line Company, LP and the Waynoka plant has access to Enogex LLC, Panhandle Eastern Pipe Line Company, LP and Southern Star Central Gas Pipeline, Inc. The Consolidator/Benedum plants have access to Kinder Morgan Texas Pipeline, Northern Natural Gas Company and El Paso Natural Gas Company. As negotiated in specific agreements, third party producers are allowed to deliver their gas in-kind to the various delivery points.

We sell our NGL production to ONEOK Hydrocarbon, L.P. under five separate agreements. The Velma agreement has an initial term expiring February 1, 2011, the Elk City/Sweetwater and Midkiff/Benedum agreements have initial terms expiring in 2013, and the Nine-Mile and Chaney Dell agreements have terms that expire in 2014. All NGL agreements are priced at the average daily Oil Price Information Service (or OPIS) price for the month for the selected market, subject to reduction by a Base Differential and quality adjustment fees.

Condensate is collected at the Velma gas plant and gathering system and currently sold to EnerWest Trading Company, LLC. Condensate collected at the Elk City/Sweetwater plants and around the Elk City/Sweetwater gathering system is currently sold to Petro Source Partners, L.P. Condensate collected at the Chaney Dell plants and around the Chaney Dell gathering system is currently sold to Plains Marketing. Condensate collected at the Consolidator/Benedum plants and around the Midkiff/Benedum gathering system is currently sold to ConocoPhillips Company, Occidental Energy Marketing, Inc. and Oasis Marketing and Transportation Corporation.

Natural Gas and NGL Hedging

Our Mid-Continent operations are exposed to certain commodity price risks. These risks result from either taking title to natural gas and NGLs, including condensate, or being obligated to purchase natural gas to satisfy contractual obligations with certain producers. We attempt to mitigate a portion of these risks through a commodity risk management program which employs a variety of financial tools. The resulting combination of the underlying physical business and the commodity risk management program attempts to convert the physical price environment that consists of floating prices to a risk-managed environment that is characterized by fixed prices; floor prices on products where we are long the commodity price; ceiling prices on products where we are short the commodity price; and/or ranges of prices, (i.e. collars). There are also risks inherent within hedging programs, including among others (i) price correlation between the physical and financial instrument deteriorating or (ii) projected physical volumes changing.

We (a) purchase natural gas and subsequently sell processed natural gas and the resulting NGLs, or (b) purchase natural gas and subsequently sell the unprocessed natural gas, or (c) gather and/or process the natural gas for a fee without taking title to the commodities. Scenario (b) exposes us to a generally neutral price risk (long sales approximate short purchases), while scenario (c) does not expose us to any price risk; in both scenarios, risk management is not required. Scenario (a) does involve commodity price risk.

We are exposed to commodity price risks when natural gas is purchased for processing. The amount and character of this price risk is a function of our contractual relationships with natural gas producers or, alternatively, a function of cost of sales. We are therefore exposed to price risk at a gross profit level rather than at a revenue level. These cost-of-sales or contractual relationships are generally of two types:

POP: requires us to pay a percentage of revenue to the producer. This results in our being net long physical natural gas and NGLs.

- Keep-Whole: generally requires us to deliver the same quantity of natural gas (measured in BTU s) at the delivery point as we received at the receipt point; any resulting NGLs produced belong to us, resulting in our being long physical NGLs and short physical natural gas.

We manage a portion of these risks by using fixed-for-floating swaps, which result in a fixed price, or by utilizing the purchase or sale of options, which result in floor prices, ceiling prices and/or a range of fixed prices. We utilize natural gas swaps and options along with natural gas basis swaps to manage our natural gas price risks. We utilize NGL and crude oil swaps and options to manage our NGL and condensate price risks.

We generally realize gains and losses from the settlement of our derivative instruments in revenue at the same time we sell the associated physical Residue Gas or NGLs. We determine gains or losses on open and closed derivative transactions as the difference between the derivative contract price and the physical price. This mark-to-market methodology uses daily closing New York Mercantile Exchange (NYMEX) prices when applicable and an internally-generated algorithm for commodities that are not traded on an open market. To ensure that these derivative instruments will be used solely for managing price risks and not for speculative purposes, we have established a committee to review our derivative instruments for compliance with our policies and procedures.

For additional information on our derivative activities and a summary of our outstanding derivative instruments as of December 31, 2009, please see Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

Our Appalachia Operations

Our Appalachia operations are principally conducted through our 49% interest in Laurel Mountain. Laurel Mountain owns and operates approximately 1,800 miles of intrastate gas gathering systems located in northeastern Appalachia, including substantial assets in the Marcellus Shale. We also own and operate approximately 80 miles of natural gas gathering pipelines in northeastern Tennessee. Laurel Mountain serves approximately 7,700 wells and experienced an average throughput of 97.0 MMCFD of natural gas for the year ended December 31, 2009. Our Tennessee systems serve approximately 190 wells and experienced an average throughput of 8.0 MMCFD of natural gas for the year ended December 31, 2009. These two gathering systems provide a means through which well owners and operators can transport the natural gas produced by their wells to interstate and public utility pipelines for delivery to customers. To a lesser extent, the gathering systems transport natural gas directly to customers. Laurel Mountain s systems are strategically located in the Appalachian Basin, which encompasses the Marcellus Shale. The Marcellus Shale is a vast, newly developing shale play experiencing a significant increase in natural gas exploration and production. The Appalachian Basin is a region that has historically been characterized by long-lived, predictable natural gas reserves that are close to major eastern U.S. natural gas markets. Substantially all of the natural gas Laurel Mountain gathers in the Appalachian Basin is derived from wells operated by Atlas Energy Resources. Laurel Mountain has a gas gathering agreement with Atlas Energy Resources, which is intended to maximize the use and expansion of the gathering systems and the amount of natural gas which Laurel Mountain gathers in the region. In addition, other natural gas producers have acreage positions in relatively close proximity to Laurel Mountain s current and planned assets, providing additional opportunities for expansion.

Appalachian Basin Overview

The Appalachian Basin includes the states of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. The Appalachian Basin is strategically located near the energy-consuming regions of the mid-Atlantic and northeastern United States.

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Natural Gas Supply

Substantially all of the natural gas Laurel Mountain gathers in the Appalachian Basin is derived from wells operated by Atlas Energy, which owns a 64.3% ownership interest in the common units of Atlas Pipeline Holdings, the parent of our General Partner, and a direct 2.2% ownership interest in us at December 31, 2009. Laurel Mountain s ability to increase the flow of natural gas through its gathering systems will be determined primarily by the number of wells drilled by Atlas Energy Resources and connected to the gathering systems; and Laurel Mountain s ability to acquire additional gathering assets and secure gathering contracts with other natural gas producers with acreage positions in the area and expand existing systems. For the year ended December 31, 2009, 250 wells were connected to the Laurel Mountain gathering system.

Natural Gas Revenue

Our Appalachia revenue is determined primarily by the amount of natural gas flowing through Laurel Mountain s and our Tennessee gathering systems and the price received for this natural gas. Laurel Mountain has an agreement with Atlas Energy Resources under which Atlas Energy Resources is obligated to pay a gathering fee that is generally the same as the gathering fee required under the terminated agreements, the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations). For the year ended December 31, 2009, Laurel Mountain received gathering fees averaging $1.05 per MCF. Laurel Mountain also charges other operator fees, which are negotiated at the time the joint venture connects wells to the gathering systems.

Because we do not buy or sell gas in connection with our Appalachia operations, we do not engage in hedging activities. Atlas Energy Resources maintains a hedging program. Since Laurel Mountain receives gathering fees from Atlas Energy Resources generally based on the selling price received by Atlas Energy Resources, inclusive of the effects of financial and physical hedging, these financial and physical hedges mitigate the risk of Laurel Mountain s arrangements.

Our Relationship with Atlas Energy

We began our operations in January 2000 by acquiring the gathering systems of Atlas Energy which, owned 64.3% of Atlas Pipeline Holdings, the parent of our general partner, which owned an 11.2% limited partner interest and a 2% general partner interest in us, at December 31, 2009. Atlas Energy also had a direct 2.2% ownership interest in us at December 31, 2009. In May, 2009, we contributed the majority of our Appalachia gathering system assets to Laurel Mountain, a joint venture in which we have a 49% interest.

Atlas Energy and its affiliates sponsor limited and general partnerships to raise funds from investors to explore for, develop and produce natural gas and, to a lesser extent, oil from locations in northeastern Appalachia. Laurel Mountain s gathering systems are connected to approximately 6,800 wells developed and operated by Atlas Energy Resources in the Appalachian Basin. Laurel Mountain gathers substantially all of the natural gas from wells operated by Atlas Energy Resources.

Natural Gas Gathering Agreements

In connection with the formation of Laurel Mountain, on June 1, 2009, Laurel Mountain entered into the following natural gas gathering agreements with Atlas Energy Resources, Atlas Energy Operating Company, LLC, Atlas America, LLC, Atlas Noble, LLC, Resource Energy, LLC and Viking Resources, LLC which superseded the master natural gas gathering agreement and omnibus agreement, both dated February 2, 2000: (1) a gas gathering agreement for natural gas on the Legacy Appalachia system with respect to the existing gathering systems and any 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 a specified area of mutual interest (the Expansion Agreement and collectively with the Legacy Agreement, the Gathering Agreements). Under these Gathering Agreements, Atlas Energy Resources will dedicate its natural gas production in the Appalachian Basin to Laurel Mountain for transportation to interstate pipeline systems,

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local distribution companies, and/or end users in the area, subject to certain exceptions. In return, Laurel Mountain is required to accept and transport Atlas Energy Resources dedicated natural gas in the Appalachian Basin subject to certain conditions.

Under the Gathering Agreements, Atlas Energy Resources is obligated to pay a gathering fee that is generally the same as the gathering fee required under the terminated agreements, the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations). Unlike the terminated agreements, Atlas Energy will not assume or guarantee Atlas Energy Resources obligation to pay the required gathering fees.

The provisions in the Gathering Agreements regarding the allocation of responsibility for constructing additional gathering lines are substantially the same as the provisions in the terminated agreements. To the extent that Atlas Energy Resources own wells or propose wells that are within 2,500 feet of Laurel Mountain s gathering system, Laurel Mountain must, at its own cost, construct up to 2,500 feet of the gathering lines as necessary to connect such wells to the gathering system. For wells more than 2,500 feet from Laurel Mountain s gathering system, if Atlas Energy Resources construct a gathering 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 gathering lines.

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

Competition

Acquisitions. We have encountered competition in acquiring midstream assets owned by third parties. In several instances we submitted bids in auction situations and in direct negotiations for the acquisition of such assets and were either outbid by others or were unwilling to meet the sellers expectations. In the future, we expect to encounter equal, if not greater, competition for midstream assets because as natural gas, crude oil and NGL prices increase the economic attractiveness of owning such assets increases.

Mid-Continent. In our Mid-Continent service area, we compete for the acquisition of well connections with several other gathering/processing operations. These operations include plants and gathering systems operated by ONEOK Field Services, Carrera Gas Company, Copano Energy, LLC, Enogex, LLC, Eagle Rock Midstream Resources, L.P., Enbridge, Inc., Hiland Partners, Penn-Virginia Resources, MarkWest Energy Partners, L.P., Mustang Fuel Corporation, DCP Midstream, West Texas Gas, BP Amoco, Southern Union Company and Targa Resources.

We believe that the principal factors upon which competition for new well connections is based are:

- the price received by an operator or producer for its production after deduction of allocable charges, principally the use of the natural gas to operate compressors; and
- the quality and efficiency of the gathering systems and processing plants that will be utilized in delivering the gas to market; and
- the access to various residue markets that provides flexibility for producers and ensures that the gas will make it to market; and
- the responsiveness to a well operator s needs, particularly the speed at which a new well is connected by the gatherer to its system.

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We believe that our relationships with operators connected to our system are good and that we present an attractive alternative for producers. However, if we cannot compete successfully, we may be unable to obtain new well connections.

Appalachia. The assets operated in the Appalachian Basin by Laurel Mountain do not encounter direct competition in its service areas at this time since Atlas Energy Resources controls the majority of the drillable acreage in the area. However, because these operations principally serve wells drilled by Atlas Energy Resources, we are affected by competitive factors affecting Atlas Energy Resources ability to obtain properties and drill wells, which affects Laurel Mountain s ability to expand gathering systems and to maintain or increase the volume of natural gas gathered and, thus, transportation revenues. Atlas Energy Resources also may encounter competition in obtaining drilling services from third-party providers. Any competition it encounters could delay Atlas Energy Resources in drilling wells for its sponsored partnerships, and thus delay the connection of wells to the Laurel Mountain gathering system. These delays would reduce the volume of natural gas that otherwise would have been gathered, thus reducing potential transportation revenues.

As the Gathering Agreements with Atlas Energy Resources generally requires it to connect wells it operates to the Laurel Mountain system, we do not expect any direct competition in connecting wells drilled and operated by Atlas Energy Resources in the future. In addition, Laurel Mountain and our Tennessee systems seek to occasionally connect wells operated by third parties. As of December 31, 2009, these systems are connected to approximately 1,000 third party wells.

Seasonality

Our business is affected by seasonal fluctuations in commodity prices. Sales volumes are also affected by various factors such as fluctuating and seasonal demands for products and variations in weather patterns from year to year. Generally, natural gas demand increases during the winter months and decreases during the summer months. Freezing conditions can disrupt our gathering process, which could adversely affect our operating results.

Regulation

Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the Federal Energy Regulatory Commission (FERC). We own a number of intrastate natural gas gathering lines in New York, Pennsylvania, Ohio, Kansas, Oklahoma and Texas that we believe would meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between the FERC-regulated transportation services and federally unregulated gathering services is the subject of regular litigation, so the classification and regulation of some of our or Laurel Mountain s gathering facilities may be subject to change based on future determinations by FERC and the courts.

Laurel Mountain s operations in Pennsylvania currently are not subject to the Pennsylvania Public Utility Commission s regulatory authority since Laurel Mountain does not provide service to the public generally and, accordingly, its activities do not constitute the operation of a public utility. In the event the Pennsylvania authorities seek to regulate Laurel Mountain s operations, our operating costs could increase and our transportation fees could be adversely affected, thereby reducing our net revenues and ability to fund our operations, pay required debt service on our credit facilities and make distributions to our General Partner and common unitholders.

We are currently subject to state ratable take, common purchaser and/or similar statutes in one or more jurisdictions in which we operate. Common purchaser statutes generally require gatherers to purchase without discrimination as to source of supply or producer, while ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. In particular, Kansas, Oklahoma and Texas have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and discrimination with respect to rates or terms of service. Should a complaint be filed or regulation by the Kansas Corporation Commission, the Oklahoma Corporation Commission or the Texas Railroad Commission become more active, our revenues could decrease. Collectively, any of these laws may restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas and NGLs. A portion of our revenue is tied to the price of natural gas and NGLs. The wholesale price of natural gas and NGLs is not currently subject to federal regulation and, for the most part, is not subject to state regulation. Sales of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transportation companies that remain subject to FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes on our operations.

Energy Policy Act of 2005. The Energy Policy Act contains numerous provisions relevant to the natural gas industry and to interstate pipelines in particular. Overall, the legislation attempts to increase supply sources by calling for various studies of the overall resource base and attempting to advantage deep water production on the Outer Continental Shelf in the Gulf of Mexico. However, the provisions of primary interest to us as an operator of natural gas gathering lines and sellers of natural gas focus on two areas: (1) infrastructure development; and (2) market transparency and enhanced enforcement. Regarding infrastructure development, the Energy Policy Act includes provisions; confirming that FERC has exclusive jurisdiction over the siting of liquefied natural gas (LNG) terminals; provides for market-based rates for certain new underground natural gas storage facilities placed into service after the date of enactment; shortens depreciable life for gathering facilities; statutorily designates FERC as the lead agency for federal authorizations and permits relating to interstate natural gas pipelines and LNG terminals; creates a consolidated record for all federal decisions relating to necessary authorizations and permits with respect to interstate natural gas pipelines and LNG terminals; and provides for expedited judicial review of any agency action involving the permitting of such facilities and review by only the D.C. Circuit Court of Appeals of any alleged failure of a federal agency to act on a permit relating to an interstate natural gas pipeline or LNG terminal by a deadline set by FERC as lead agency. Such provisions, however, do not apply to review and authorization under the Coastal Zone Management Act of 1972. Regarding market transparency and manipulation, the Natural Gas Act has been amended to prohibit market manipulation and directs FERC to prescribe rules designed to encourage the public provision of data and reports regarding the price of natural gas in wholesale markets. The Natural Gas Act and the Natural Gas Policy Act were also amended to increase monetary criminal penalties to $1,000,000 from the $5,000 amount specified in current law and to add and increase civil penalty authority to be administered by FERC to $1,000,000 per day per violation without any limitation as to total amount.

At present, none of our gathering lines qualify as interstate natural gas transmission systems subject to FERC regulation under the Natural Gas Act. Accordingly, the provisions of the Energy Policy Act have only limited applicability to us, primarily in our capacity as a seller of natural gas.

Environmental Matters

The operation of pipelines, plant and other facilities for gathering, compressing, treating, processing, or transporting natural gas, natural gas liquids and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction and operating activities in sensitive areas such as wetlands, coastal regions, tribal lands or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operators; and
- enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where pollutants or wastes have been disposed 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 pollutants or wastes into the environment.

We believe that our operations are in substantial compliance with applicable environmental laws and regulations and that compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, we cannot assure you that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs.

Hazardous Waste. Our operations generate wastes, including some hazardous wastes that are subject to the federal Resource Conservation and Recovery Act, as amended, or RCRA and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the solid waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

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 exploration and production wastes could increase our costs to manage and dispose of such wastes.

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Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or CERCLA, also known as Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum as well as natural gas is excluded from CERCLA s definition of hazardous substance, in the course of our ordinary operations we may generate wastes that may fall within the definition of a hazardous substance. CERCLA authorizes the Environmental Protection Agency, or EPA, and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several, strict liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. There is evidence that petroleum spills or releases have occurred at some of the properties owned or leased by us, however, none of these spills or releases were material and we believe that all of them have been remediated. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbons or wastes 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 wastes (including waste disposed of by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform operations to prevent future contamination.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Water Discharges. Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants is prohibited unless authorized by a permit or other agency approval. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of pollutants from our pipelines or facilities could result in administrative, civil and criminal penalties as well as significant remedial obligations. Further, natural

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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 many producers 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 their business and operations, which may have an impact on our operations.

Pipeline Safety. Our pipelines are subject to regulation by the U.S. Department of Transportation, or DOT, under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA. The NGPSA authorizes the DOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases, and requires any entity that owns or operates pipeline facilities to comply with the regulations. The U.S. Department of Transportation s Pipeline and Hazardous Material Safety Administration, or PHMSA, acting through the Office of Pipeline Safety, or OPS, administers the national regulatory program to assure safe transportation of natural gas, petroleum, and other hazardous materials by pipeline, by administering the Federal Pipeline Safety Regulations to (1) assure safety in design, construction, inspection, testing, operation, and maintenance of pipeline facilities and (2) set out parameters for administering the pipeline safety program.

Our operations are required to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with existing PHMSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the PHMSA could result in additional requirements and costs.

PHMSA recently finalized a series of rules intended to require pipeline operators to develop integrity management programs for gas transportation pipelines (including gathering lines) that, in the event of a failure, could affect high consequence areas. High consequence areas are currently defined as areas with specified population densities, buildings containing populations of limited mobility, and areas where people gather that are located along the route of a pipeline. To assure uniform implementation of the pipeline safety program nationwide, a Federal/State partnership of the Texas Railroad Commission, the Oklahoma Corporation Commission and other state agencies have adopted similar regulations applicable to intrastate gathering and transportation lines. Compliance with these rules has not had a materially adverse effect on our operations but there is no assurance that this will continue in the future.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans, and prolonged exposure can result in death. The gas produced at our Velma gas plant contains high levels of hydrogen sulfide, and we employ numerous safety precautions at the system to ensure the safety of our employees. There are various federal and state environmental and safety requirements for handling sour gas, and we are in substantial compliance with all such requirements.

Chemicals of Interest. We operate several facilities that are subject to registration with the U.S. Department of Homeland Security, or DHS, in order to identify quantities of various chemicals that are stored at the sites. These facilities are the Velma, Chaney Dell, Waynoka, Chester, Nine Mile, Sweetwater and Elk City gas processing plants, and the Prentiss Treating facility in Oklahoma; and the Consolidator and Benedum gas processing plants in Texas. The liquid hydrocarbons that are recovered and stored as a result of the facility processing activities, as well as various chemicals utilized within the processes, have been identified and registered with DHS. These registration requirements for *Chemical of Interest* were first promulgated by DHS in 2008 and we are currently in compliance with the Department s requirements.

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Green House Gases. In October 2009, the EPA published rules in Title 40 of the Code of Federal Regulations, part 98 (40 CFR 98) requiring mandatory reporting of greenhouse gases. The rule specifies methods by which entities that produce these gases, which include Carbon Dioxide (CO_2) and Methane (CH_4), must inventory, monitor and report such gases. The United States Congress is also considering legislation to address the production and reduction of greenhouse gases. Additionally, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. As an alternative to cap and trade programs, Congress may consider the implementation of a carbon tax program. The cap and trade programs could require major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we process. Depending on the design and implementation of carbon tax programs, our operations could face additional taxes and higher costs of doing business. Although we would not be impacted to a greater degree than other similarly situated gatherers and processors of natural gas or NGLs, a stringent greenhouse gas control program could result in a significant effect on our cost of doing business. However, we are currently unable to assess the timing and effect of the pending legislation.

Properties

As of December 31, 2009, our principal facilities in Appalachia include approximately 80 miles of 2 to 12 inch diameter pipeline operated by our Tennessee gathering systems and approximately 1,800 miles of 2 to 12 inch diameter pipeline operated by Laurel Mountain. Our principal facilities in the Mid-Continent consist of eight natural gas processing plants, one treating facility, and approximately 9,100 miles of active 2 to 30 inch diameter pipeline. Substantially all of our gathering systems are constructed within rights-of-way granted by property owners named in the appropriate land records. In a few cases, property for gathering system purposes was purchased in fee. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

The following tables set forth certain information relating to our gas processing facilities and natural gas gathering systems:

Gas Processing Facilities

Facility	Location	Year of Initial Construction	Design Throughput Capacity (MMCFD)
Elk City plant	Beckham County, OK	1984	130
Prentiss treating facility	Beckham County, OK	2003	200
Sweetwater plant	Beckham County, OK	2006	120[1]
Nine-Mile plant	Dewey County, OK	2009	120
Velma plant	Stephens County, OK	Updated 2003	100
Waynoka plant	Woods County, OK	2006	200
Chester plant	Woodward County, OK	1981	28
Consolidator plant[2]	Reagan County, TX	2009	150
Benedum plant	Upton County, TX	Updated 1981	43

(1) Exclusive of 60 MMCFD owned by Penn Virginia Resources

(2) Replaced 110 MMCFD Midkiff plant, which has been shut down. Midkiff plant is available for processing if natural gas supply increases beyond the Consolidator plant capacity.

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Natural Gas Gathering Systems

System	Location	Approximate Active Miles of Pipe
Chaney Dell	North Central Oklahoma and Southern Kansas	4,100
Elk City/Sweetwater	Western Oklahoma and Texas Panhandle	800
Velma	Southern Oklahoma and Northern Texas	1,200
Midkiff/Benedum	West Texas	3,000
Laurel Mountain	Northeast Appalachia	1,800
Tennessee	Northeastern Tennessee	80

Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections. These imperfections have not materially interfered, and we do not expect that they will materially interfere, with the conduct of our business. In many instances, lands over which rights-of-way have been obtained are subject to prior liens which have not been subordinated to the rights-of-way grants. In a few instances, our rights-of-way are revocable at the election of the land owners. In some cases, not all of the owners named in the appropriate land records have joined in the rights-of-way grants, but in substantially all such cases signatures of the owners of majority interests have been obtained. Substantially all permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets, and state highways, where necessary, although in some instances these permits are revocable at the election of the grantor. Substantially all permits have also been obtained from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor s election.

Certain of our rights to lay and maintain pipelines are derived from recorded gas well leases, with respect to wells that are currently in production; however, the leases are subject to termination if the wells cease to produce. In some of these cases, the right to maintain existing pipelines continues in perpetuity, even if the well associated with the lease ceases to be productive. Because many of these leases affect wells at the end of lines, these rights-of-way will not be used for any other purpose once the related wells cease to produce.

Employees

As is commonly the case with publicly-traded limited partnerships, we do not directly employ any of the persons responsible for our management or operations. In general, employees of Atlas Energy and its affiliates manage our gathering systems and operate our business. Atlas Energy employed approximately 310 people at December 31, 2009 who provided direct support to our operations.

Affiliates of our General Partner will conduct business and activities of their own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition between us, our General Partner and affiliates of our General Partner for the time and effort of the officers and employees who provide services to our General Partner. Apart from our Chairman, Vice Chairman and for nine months with respect to our former Chief Financial Officer, the officers of our General Partner who provide services to us are generally assigned solely to our operations. However, they are not required to work full time on our affairs. These officers may also devote time to the affairs of our General Partner s affiliates and be compensated by these affiliates for the services rendered to them. There may be conflicts between us and affiliates of our General Partner regarding the availability of these officers to manage us.

Available Information

We make our periodic reports under the Securities Exchange Act of 1934, including our annual report on Form 10-K, our quarterly reports on Form 10-Q and our current reports on Form 8-K, available through our website at www.atlaspipelinepartners.com. To view these reports, click on Investor Relations, then SEC Filings. You may also receive, without charge, a paper copy of any such filings by request to us at 1550

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Coraopolis Heights Road, Moon Township, Pennsylvania 15108, telephone number (412) 262-2830. A complete list of our filings is available on the Securities and Exchange Commission s website at www.sec.gov. Any of our filings are also available at the Securities and Exchange Commission s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information.

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ITEM 1A. RISK FACTORS

Partnership interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Risks Relating to Our Business

The amount of cash we generate depends, in part, on factors beyond our control.

The amounts of cash that we generate may not be sufficient for us to pay distributions in the future. Our ability to make cash distributions depends primarily on our cash flow. Cash distributions do not depend directly on our profitability, which is affected by non-cash items. Therefore, cash distributions may be made during periods when we record losses and may not be made during periods when we record profits. The actual amounts of cash we generate will depend upon numerous factors relating to our business which may be beyond our control, including:

- the demand for natural gas and NGLs;
- the price of natural gas and NGLs (including the volatility of such prices);
- the amount of NGL content in the natural gas we process;
- the volume of natural gas we gather;
- efficiency of our gathering systems and processing plants;
- expiration of significant contracts;
- continued development of wells for connection to our gathering systems;
- our ability to connect new wells to our gathering systems;
- our ability to integrate newly formed ventures or acquired businesses with our existing operations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of fractionation capacity;
- the expenses we incur in providing our gathering services;

the cost of acquisitions and capital improvements;

our issuance of equity securities;

required principal and interest payments on our debt;

fluctuations in working capital;

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- prevailing economic conditions;
- fuel conservation measures;
- alternate fuel requirements;
- the strength and financial resources of our competitors;
- the effectiveness of our hedging program and the creditworthiness of our hedging counterparties;
- governmental (including environmental and tax) laws and regulations; and
- technical advances in fuel economy and energy generation devices.

In addition, the actual amount of cash that we will have available for distribution will depend on other factors, including:

- the level of capital expenditures we make;
- the sources of cash used to fund our acquisitions;
- limitations on our access to capital or the market for our common units and notes;
- our debt service requirements and requirements to pay dividends on our outstanding preferred units, and restrictions on distributions contained in our current or future debt agreements; and
- the amount of cash reserves established by our General Partner for the conduct of our business.

We cannot borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings under our partnership agreement. Because we cannot borrow money to pay distributions unless we establish a facility that meets the definition contained in our partnership agreement, our ability to pay a distribution in any quarter is solely dependent on our ability to generate sufficient operating surplus with respect to that quarter.

Our financial and operating performance may fluctuate significantly from quarter to quarter. We may be unable to continue to generate sufficient cash flow to fund our operations, pay required debt service on our credit facilities and make distributions to our unitholders. If we are unable to do so, we may be required to sell assets or equity, reduce capital expenditures, refinance all or a portion of our existing indebtedness or obtain additional financing. We may be unable to do so on acceptable terms, or at all.

Economic conditions and instability in the financial markets could negatively impact our business.

Our operations are affected by the continuing effects of the financial crisis and related turmoil in the global financial system. The consequences of an economic recession and the effects of the financial crisis include a lower level of economic activity and increased volatility in energy prices. This may result in a decline in energy consumption and lower market prices for oil and natural gas, and has resulted in a reduction in drilling activity in our service area and in wells currently connected to our pipeline system being shut in by their operators until prices improve.

Any of these events may adversely affect our revenues and our ability to fund capital expenditures and in turn, may impact the cash that we have available to fund our operations, pay required debt service on our credit facility and make distributions to our unitholders.

Continuing instability in the financial markets, as a result of recession or otherwise, has increased the cost of capital while the availability of funds from those markets has diminished significantly. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. Disruptions in the capital and credit markets could negatively impact our access to liquidity needed for our business and impact our flexibility to react to changing economic and business conditions. Any disruption could require us to take measures to conserve cash until the markets stabilize or until we can arrange alternative credit arrangements or other funding for our business needs. Such measures could include reducing or delaying business activities, reducing our operations to lower expenses, reducing other discretionary uses of cash, and reducing or eliminating future distributions to our unitholders. We may be unable to execute our growth strategy, take advantage of business opportunities or to respond to competitive pressures, any of which could negatively impact our business.

The current economic situation could have an adverse impact on our lenders, producers, key suppliers or other customers, causing them to fail to meet their obligations to us. Market conditions could also impact our derivative instruments. If a counterparty is unable to perform its obligations and the derivative instrument is terminated, our cash flow and ability to make required debt service payments on our credit facility and pay distributions could be impacted. The uncertainty and volatility surrounding the global financial crisis may have further impacts on our business and financial condition that we currently cannot predict or anticipate.

We are affected by the volatility of prices for natural gas and NGL products.

We derive a majority of our gross margin from POP and Keep-Whole contracts. As a result, our income depends to a significant extent upon the prices at which we buy and sell natural gas and at which we sell NGLs and condensate. Average estimated unhedged 2010 market prices for NGLs, natural gas and condensate, based upon NYMEX forward price curves as of February 15, 2010, are $1.10 per gallon, $5.71 per MMBTU and $76.26 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended December 31, 2010 by approximately $27.2 million. Additionally, changes in natural gas prices may indirectly impact our profitability since prices can influence drilling activity and well operations, and could cause operators of wells currently connected to our pipeline system or that we expect will be connected to our system to shut in their production until prices improve, thereby affecting the volume of gas we gather and process. Historically, the price of both natural gas and NGLs has been subject to significant volatility in response to relatively minor changes in the supply and demand for natural gas and NGL products, market uncertainty and a variety of additional factors beyond our control, including those we describe in The amount of cash we generate depends, in part, on factors beyond our control, above. Oil prices have traded in a range of $33.98 per barrel to $81.37 per barrel in 2009, while natural gas prices have traded in a range of $2.51 per MMBTU to $6.07 per MMBTU, during the same time period. We expect this volatility to continue. This volatility may cause our gross margin and cash flows to vary widely from period to period. Our risk management strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the throughput volumes. Moreover, derivative instruments are subject to inherent risks, which we describe in Our price risk management strategies may fail to protect us and could reduce our gross margin and cash flow.

Our price risk management strategies may fail to protect us and could reduce our gross margin and cash flow.

Our operations expose us to fluctuations in commodity prices. We utilize derivative contracts related to the future price of crude oil, natural gas and NGLs with the intent of reducing the volatility of our cash flows due to fluctuations in commodity prices. To the extent we protect our commodity price using certain derivative contracts we will forego the benefits we would otherwise experience if commodity prices were to change in our favor. Our commodity price risk management activity may fail to protect or could harm us because, among other things:

- entering into derivative instruments can be expensive, particularly during periods of volatile prices;

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- available derivative instruments may not correspond directly with the risks against which we seek protection;
- price correlation between the physical transaction and the derivative transaction could change;
- the anticipated physical transaction could be different than projected due to changes in contracts, lower production volumes or other operational impacts, resulting in possible losses on the derivative instrument which is not offset by income on the anticipated physical transaction; and
- the party owing money in the derivative transaction may default on its obligation to pay.

Due to the accounting treatment of our derivative contracts, increases in prices for natural gas, crude oil and NGLs could result in non-cash balance sheet reductions.

With the objective of enhancing the predictability of future revenues, from time to time we enter into natural gas, natural gas liquids and crude oil derivative contracts. We account for these derivative contracts by applying the mark-to-market accounting treatment required for these derivative contracts. We could recognize incremental derivative liabilities between reporting periods resulting from increases or decreases in reference prices for natural gas, crude oil and NGLs, which could result in our recognizing a non-cash loss in our consolidated statements of operations and a consequent non-cash decrease in our Partners Capital between reporting periods. Any such decrease could be substantial. In addition, we may be required to make cash payments upon the termination of any of these derivative contracts.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could negatively impact our business.

We have historically experienced minimal collection issues with our counterparties; however our revenue and receivables are highly concentrated in a few key customers and therefore we are subject to risks of loss resulting from nonpayment or nonperformance by our key customers. In an attempt to reduce this risk, credit limits have been established for each customer and we attempt to limit our credit risk by obtaining letters of credit or other appropriate forms of security. Nonetheless, we have key customers whose credit risk cannot realistically be otherwise mitigated.

Due to our lack of asset diversification, negative developments in our operations would reduce our ability to fund our operations, pay required debt service on our credit facilities and make distributions to our common unitholders.

We rely exclusively on the revenues generated from our gathering and processing operations, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to our lack of asset-type diversification, a negative development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

The amount of natural gas we gather will decline over time unless we are able to attract new wells to connect to our gathering systems.

Production of natural gas from a well generally declines over time until the well can no longer economically produce natural gas and is plugged and abandoned. Failure to connect new wells to our gathering

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systems could, therefore, result in the amount of natural gas we gather declining substantially over time and could, upon exhaustion of the current wells, cause us to abandon one or more of our gathering systems and, possibly, cease operations. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing wells that are not committed to other systems, the level of drilling activity near our gathering systems and, in the Mid-Continent region, our ability to attract natural gas producers away from our competitors gathering systems.

Over time, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. A decrease in exploration and development activities in the fields served by our gathering and processing facilities could result if there is a sustained decline in natural gas prices which, in turn, would lead to a reduced utilization of these assets. The decline in the credit markets, the lack of availability of credit, debt or equity financing and the decline in natural gas prices may result in a reduction of producers exploratory drilling. We have no control over the level of drilling activity in our service areas, the amount of reserves underlying wells that connect to our systems and the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, drilling costs, geological considerations, governmental regulation and the availability and cost of capital. In a low price environment, such as currently exists, producers may determine to shut in wells already connected to our systems until prices improve. Because our operating costs are fixed to a significant degree, a reduction in the natural gas volumes we gather or process would result in a reduction in our gross margin and cash flows.

The amount of natural gas we gather or process may be reduced if the natural gas liquids pipelines to which we deliver NGLs cannot or will not accept the NGLs.

If one or more of the pipelines to which we deliver NGLs has service interruptions, capacity limitations or otherwise does not accept the NGLs we sell to or transport on, and we cannot arrange for delivery to other pipelines, the amount of NGLs we sell or transport may be reduced. Since our revenues depend upon the volumes of NGLs we sell or transport, this could result in a material reduction in our gross margin and cash flows.

The amount of natural gas we gather, treat or process may be reduced if the intrastate and interstate pipelines to which we deliver gas cannot or will not accept the gas.

Our gathering systems principally serve as intermediate transportation facilities between wells connected to our systems and the intrastate or interstate pipelines to which we deliver natural gas. If one or more of these pipelines has service interruptions, capacity limitations or otherwise does not accept the natural gas we gather, and we cannot arrange for delivery to other pipelines, local distribution companies or end users, the amount of natural gas we gather may be reduced. Since our revenues depend upon the volumes of natural gas we gather, this could result in a material reduction in our gross margin and cash flows.

If we are unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then our cash flows could be reduced.

The construction of additions to our existing gathering assets may require us to obtain new rights-of-way before constructing new pipelines. We may be unable to obtain rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then our cash flows could be reduced.

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The success of our interest in the Laurel Mountain joint venture depends upon Atlas Energy Resources ability to drill and complete commercially producing wells.

Substantially all of the wells connected to the Laurel Mountain gathering systems in our Appalachia service area are drilled and operated by Atlas Energy Resources for drilling investment partnerships sponsored by it. As a result, Laurel Mountain currently depends principally upon the success of Atlas Energy Resources in sponsoring drilling investment partnerships and completing wells for these partnerships. Atlas Energy Resources operates in a highly competitive environment for acquiring undeveloped leasehold acreage and attracting capital. Atlas Energy Resources may not be able to compete successfully in the future in acquiring undeveloped leasehold acreage or in raising additional capital through its drilling investment partnerships. If Atlas Energy Resources cannot or does not continue to sponsor drilling investment partnerships, if the amount of money raised by those partnerships decreases, or if the number of wells actually drilled and completed as commercially producing wells decreases, the amount of natural gas gathered via the Laurel Mountain systems would substantially decrease and could, upon exhaustion of the wells currently connected to the gathering systems, cause the joint venture to abandon one or more of the gathering systems, which may reduce our gross margin and cash flows.

The failure of Atlas Energy Resources to perform its obligations under the Laurel Mountain Gathering Agreements may adversely affect our business.

Substantially all of Laurel Mountain s revenues currently consist of the fees received under the Gathering Agreements and other transportation agreements Laurel Mountain has with Atlas Energy Resources. We expect to derive a portion of our gross margin from the services provided under contracts Laurel Mountain has with Atlas Energy Resources for the foreseeable future. Any factor or event adversely affecting Atlas Energy Resources business or its ability to perform under its contracts with Laurel Mountain or any default or nonperformance by Atlas Energy Resources of its contractual obligations, could reduce our gross margin and cash flows.

The success of our Mid-Continent operations depends upon our ability to continually find and contract for new sources of natural gas supply from unrelated third parties.

Unlike our interest in Laurel Mountain, none of the drillers or operators in our Mid-Continent service area is an affiliate of ours. Moreover, our agreements with most of the producers with which our Mid-Continent operations do business generally do not require them to dedicate significant amounts of undeveloped acreage to our systems. While we do have some undeveloped acreage dedicated on our systems, most notably with our partner Pioneer on our Midkiff/Benedum system, we do not have assured sources to provide us with new wells to connect to our Mid-Continent gathering systems. Failure to connect new wells to our Mid-Continent operations, as described in The amount of natural gas we gather will decline over time unless we are able to attract new wells to connect to our gathering systems, above, will reduce our gross margin and cash flows.

Our Mid-Continent operations currently depend on certain key producers for their supply of natural gas; the loss of any of these key producers could reduce our revenues.

During 2009, Chesapeake Energy Corporation, Pioneer, Sandridge Energy, Inc., Conoco Phillips, XTO Energy Inc., Henry Petroleum, L.P., Linn Energy, LLC, Kaiser-Francis Oil Company, Sanguine Gas Exploration, LLC, Forest Oil Corporation and Apache Corporation accounted for a significant amount of our Mid-Continent operations natural gas supply. If these producers reduce the volumes of natural gas that they supply to us, our gross margin and cash flows would be reduced unless we obtain comparable supplies of natural gas from other producers.

The curtailment of operations at, or closure of, any of our processing plants could harm our business.

If operations at any of our processing plants were to be curtailed, or closed, whether due to accident, natural catastrophe, environmental regulation or for any other reason, our ability to process natural gas from the relevant gathering system and, as a result, our ability to extract and sell NGLs, would be harmed. If this curtailment or stoppage were to extend for more than a short period, our gross margin and cash flows would be materially reduced.

We may face increased competition in the future in our Mid-Continent operations.

Our Mid-Continent operations face competition for well connections. DCP Midstream, LLC, ONEOK, Inc., Carrera Gas Company, Copano Energy, LLC and Enogex, LLC operate competing gathering systems and processing plants in our Velma service area. In our Elk City, Sweetwater and Nine-Mile service area, ONEOK Field Services, Eagle Rock Midstream Resources, L.P., Enbridge Energy Partners, L.P., CenterPoint Energy, Inc., Penn-Virginia Resources, MarkWest Energy Partners, L.P. and Enogex LLC operate competing gathering systems and processing plants. Hiland Partners, DCP Midstream, Mustang Fuel Corporation and ONEOK Partners operate competing gathering systems and processing plants in our Chaney Dell service area. DCP Midstream, West Texas Gas, BP Amoco, Southern Union Company and Targa Resources operate competing gathering systems and processing plants in our Midkiff/Benedum service area. Some of our competitors have greater financial and other resources than we do. If these companies become more active in our Mid-Continent service area, we may not be able to compete successfully with them in securing new well connections or retaining current well connections. If we do not compete successfully, the amount of natural gas we gather, process and treat will decrease, reducing our gross margin and cash flows.

The acquisitions of the Chaney Dell and the Midkiff/Benedum systems in July 2007 and the contribution of our Appalachia assets to Laurel Mountain in May 2009 have substantially changed our business, making it difficult to evaluate our business based upon our historical financial information.

The acquisitions of the Chaney Dell and Midkiff/Benedum systems have significantly increased our size and substantially redefined our business plan, expanded our geographic market and resulted in large changes to our revenues and expenses. In May 2009, we contributed the majority of our Appalachia gathering system assets to Laurel Mountain, a joint venture in which we have a 49% interest. Income for Laurel Mountain is recognized as equity income on our statement of operations. As a result of these transactions, and our continued plan to acquire and integrate additional companies that we believe present attractive opportunities, our financial results for any period or changes in our results across periods may continue to dramatically change. Our historical financial results, therefore, should not be relied upon to accurately predict our future operating results, thereby making the evaluation of our business more difficult.

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

Any acquisition involves potential risks, including, among other things:

- the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- mistaken assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- delays in obtaining any required regulatory approvals or third party consents;
- the imposition of conditions on any acquisition by a regulatory authority;

an inability to integrate successfully or timely the businesses we acquire;

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- 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 ultimately be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future growth and our ability to make or increase distributions.

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.

We have an active, on-going program to identify potential acquisitions. Our integration of previously independent operations with our own can be a complex, costly and time-consuming process. The difficulties of combining these systems with existing systems 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 pipeline safety-related records and procedures;
- integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;
- the diversion of management s attention from other business concerns;
- customer or key employee loss from the acquired businesses;

a significant increase in our indebtedness; and

potential environmental or regulatory liabilities and title problems.

Our investment and the additional overhead costs we incur to grow our NGL business may not deliver the expected incremental volume or cash flow. Costs incurred and liabilities assumed in connection with the acquisition and increased capital expenditures and overhead costs incurred to expand our operations could harm our business or future prospects, and result in significant decreases in our gross margin and cash flows.

Our construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could impair our results of operations and financial condition.

One of the ways we may grow our business is through the construction of new assets, such as our recent Madill-to-Velma pipeline and the Nine-Mile and Consolidator plants. The construction of additions or modifications to our existing systems and facilities, and the construction of new assets, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. Any projects we undertake may not be completed on schedule at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a gathering system, the construction may occur over an extended

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period of time, and we will not receive any material increase in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which growth does not materialize. Since we are not engaged in the exploration for, and development of, natural gas reserves, we often do not have access to estimates of potential reserves in an area before constructing facilities in the area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, the estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could impair our results of operations and financial condition. In addition, our actual revenues from a project could materially differ from expectations as a result of the price of natural gas, the NGL content of the natural gas processed and other economic factors described in this section.

We recently completed construction of an expansion to our Nine-Mile and Consolidator natural gas processing plants. We also recently completed a pipeline to extend our Velma system into the Madill area. From these projects, we expect to generate additional incremental cash flow. We also continue to expand the natural gas gathering systems surrounding our other facilities in order to maximize plant throughput. In addition to the risks discussed above, expected incremental revenue from the recent projects could be reduced or delayed due to the following reasons:

- difficulties in obtaining equity or debt financing for additional construction and operating costs;
- difficulties in obtaining permits or other regulatory or third-party consents;
- additional construction and operating costs exceeding budget estimates;
- revenue being less than expected due to lower commodity prices or lower demand;
- difficulties in obtaining consistent supplies of natural gas; and
- terms in operating agreements that are not favorable to us.

We may not be able to execute our growth strategy successfully.

Our strategy contemplates substantial growth through both the acquisition of other gathering systems and processing assets and the expansion of our existing gathering systems and processing assets. Our growth strategy involves numerous risks, including:

- we may not be able to identify suitable acquisition candidates;
- we may not be able to make acquisitions on economically acceptable terms for various reasons, including limitations on access to capital and increased competition for a limited pool of suitable assets;
- our costs in seeking to make acquisitions may be material, even if we cannot complete any acquisition we have pursued;
- irrespective of estimates at the time we make an acquisition, the acquisition may prove to be dilutive to earnings and operating surplus;

we may encounter delays in receiving regulatory approvals or may receive approvals that are subject to material conditions;

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- we may encounter difficulties in integrating operations and systems; and

- any additional debt we incur to finance an acquisition may impair our ability to service our existing debt.

Limitations on our access to capital or the market for our common units will impair our ability to execute our growth strategy.

Our ability to raise capital for acquisitions and other capital expenditures depends upon ready access to the capital markets. Historically, we have financed our acquisitions, and to a much lesser extent, expansions of our gathering systems by bank credit facilities and the proceeds of public and private debt and equity offerings of our common units and preferred units of our operating partnership. If we are unable to access the capital markets, we may be unable to execute our strategy of growth through acquisitions.

Our debt levels and restrictions in our credit facility could limit our ability to fund operations, pay required debt service on our credit facility and make distributions to our unitholders.

We have a significant amount of debt. We will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, which will reduce the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms, or at all.

Our credit facility contains covenants limiting the ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions to unitholders. It also contains covenants requiring us to maintain certain financial ratios and places limits on capital expenditures. In addition, under our credit facility, we were not permitted to pay cash distributions for the last three quarters of fiscal 2009, and are permitted to pay cash distributions beginning with the quarter ending March 31, 2010, only if, (i) on a pro forma basis after such payment, our senior secured leverage ratio, defined generally as the ratio of total secured funded debt that is not subordinated to the credit facility to consolidated EBITDA, as defined in the credit agreement, is less than or equal to 2.75 to 1.00 and (ii) our minimum liquidity, defined generally as cash and cash equivalents less restricted cash plus amounts available for borrowing under the revolver portion of the credit facility, is at least $50 million.

If we do not pay distributions on our common units with respect to 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 receive such payments in the future.

We may issue additional units, which may increase the risk of not having sufficient available cash to make distributions at prior per unit distribution levels, once distributions are reinstated.

We have wide discretion to issue additional units, including units that rank senior to our common units as to quarterly cash distributions, on the terms and conditions established by our General Partner. The payment of distributions on these 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 the common units.

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Regulation of our gathering operations could increase our operating costs, decrease our revenues, or both.

Currently our gathering and processing of natural gas is exempt from regulation under the Natural Gas Act of 1938. However, the implementation of new laws or policies, or changed interpretations of existing laws, could subject our gathering and processing operations to regulation by FERC under the Natural Gas Act, the Natural Gas Policy Act, or other laws. We expect that any such regulation would increase our costs, decrease our gross margin and cash flows, or both.

Even if our gathering and processing operations are not generally subject to regulation under the Natural Gas Act, FERC regulation will still affect our business and the market for our products. FERC s policies and practices affect a range of natural gas pipeline activities, including, for example, its policies on interstate natural gas pipeline open access transportation, ratemaking, capacity release, environmental protection and market center promotion, which indirectly affect intrastate markets. FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. We cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Since federal law generally leaves any economic regulation of natural gas gathering to the states, state and local regulations may also affect our business. Matters subject to such regulation include access, rates, terms of service and safety. For example, our gathering lines are subject to ratable take, common purchaser, and similar statutes in one or more jurisdictions in which we operate. Common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer, while ratable take statutes generally require gatherers to take, without discrimination, natural gas production that may be tendered to the gatherer for handling. Kansas, Oklahoma and Texas have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and discrimination with respect to rates or terms of service. Should a complaint be filed or regulation by the Texas Railroad Commission, Oklahoma Corporation Commission or Kansas Corporation Commission become more active, our revenues could decrease. Collectively, all of these statutes may restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

Compliance with pipeline integrity regulations issued by the DOT and state agencies could result in substantial expenditures for testing, repairs and replacement.

DOT and state agency regulations require pipeline operators to develop integrity management programs for transportation pipelines located in high consequence areas. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

We do not believe that the cost of implementing integrity management program testing along certain segments of our pipeline will have a material effect on our results of operations. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial.

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Our midstream natural gas operations may incur significant costs and liabilities resulting from a failure to comply with new or existing environmental regulations or a release of hazardous substances into the environment.

The operations of our gathering systems, plant and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. These laws and regulations can restrict or impact our business activities in many ways, including restricting the manner in which we dispose of substances, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. 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 impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed 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 substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations including releases of substances into the environment, and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, 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 could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance.

Our midstream natural gas operations may incur significant costs and liabilities resulting from new environmental regulations related to climate control.

Federal and state governments are considering and/or implementing measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. As an alternative to cap and trade programs, Congress may consider the implementation of a carbon tax program. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we process. Depending on the design and implementation of carbon tax programs, our operations could face additional taxes and higher costs of doing business. Although we would not be impacted to a greater degree than other similarly situated gatherers and processors of natural gas or NGLs, a stringent greenhouse gas control program could result in a significant effect on our cost of doing business.

Litigation or governmental regulation relating to environmental protection and operational safety may result in substantial costs and liabilities.

Our operations are subject to federal and state environmental laws under which owners of natural gas pipelines can be liable for clean-up costs and fines in connection with any pollution caused by their pipelines. We may also be held liable for clean-up costs resulting from pollution which occurred before our acquisition of the gathering systems. In addition, we are subject to federal and state safety laws that dictate the type of pipeline, quality of pipe protection, depth of pipelines, methods of welding and other construction-related standards. Any violation of environmental, construction or safety laws could impose substantial liabilities and costs on us.

We are also subject to the requirements of OSHA, and comparable state statutes. Any violation of OSHA could impose substantial costs on us.

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We cannot predict whether or in what form any new legislation or regulatory requirements might be enacted or adopted, nor can we predict our costs of compliance. In general, we expect that new regulations would increase our operating costs and, possibly, require us to obtain additional capital to pay for improvements or other compliance action necessitated by those regulations.

We are subject to operating and litigation risks that may not be covered by insurance.

Our operations are subject to all operating hazards and risks incidental to gathering and processing natural gas and NGLs. These hazards include:

- damage to pipelines, plants, related equipment and surrounding properties caused by floods and other natural disasters;
- inadvertent damage from construction and farm equipment;
- leakage of natural gas, NGLs and other hydrocarbons;
- fires and explosions;
- other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations; and
- acts of terrorism directed at our pipeline infrastructure, production facilities and surrounding properties.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for some of our insurance policies have increased substantially, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, our gross margin and cash flows would be materially reduced.

Risks Related to Our Ownership Structure

Atlas Energy and its affiliates, including Atlas Energy Resources, have conflicts of interest and limited fiduciary responsibilities, which may permit them to favor their own interests to the detriment of our unitholders.

Atlas Energy and its affiliates own and control our General Partner, which also owns an 11.2% limited partner interest in us. We do not have any employees and rely solely on employees of Atlas Energy and its affiliates, who serve as our agents, including all of the senior managers who operate our business. A number of officers and employees of Atlas Energy also own interests in us. Conflicts of interest may arise between Atlas Energy, our General Partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our General Partner may favor its own interests and the interests of its affiliates over our interests and the interests of our unitholders. These conflicts include, among others, the following situations:

- Employees of Atlas Energy who provide services to us also devote time to the businesses of Atlas Energy in which we have no economic interest. If these separate activities are greater than our activities, there could be material competition for the time and effort of the employees who provide services to our General Partner, which could result in insufficient attention to the management and operation of our business.

Neither our partnership agreement nor any other agreement requires Atlas Energy to pursue a future business strategy that favors us, apart from our and Laurel Mountain s agreements with Atlas Energy Resources relating to our Appalachia operations, or use our assets for gathering or processing services we provide. Atlas Energy s directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of Atlas Energy.

Our General Partner is allowed to take into account the interests of parties other than us, such as Atlas Energy, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to us.

Our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates, including our agreements with Atlas Energy Resources.

Conflicts of interest with Atlas Energy and its affiliates, including the foregoing factors, could exacerbate periods of lower or declining performance, or otherwise reduce our gross margin and cash flows.

Cost reimbursements due our General Partner may be substantial and will reduce the cash available for distributions to our unitholders.

We reimburse Atlas Energy, our General Partner and its affiliates, including officers and directors of Atlas Energy, for all expenses they incur on our behalf. Our General Partner has sole discretion to determine the amount of these expenses. In addition, Atlas Energy provides us with services for which we are charged reasonable fees as determined by Atlas Energy in its sole discretion. The reimbursement of expenses or payment of fees could adversely affect our ability to fund our operations, pay required debt service on our credit facilities and make distributions to our unitholders.

Our control of the Chaney Dell and Midkiff/Benedum systems is limited by provisions of the limited liability company operating agreements with Anadarko and, with respect to the Midkiff/Benedum system, the operation and expansion agreement with Pioneer.

The managing member of each of the limited liability companies which owns the interests in the Chaney Dell and Midkiff/Benedum systems is our subsidiary. However, the consent of Anadarko is required for specified extraordinary transactions, such as admission of new members, engaging in transactions with our affiliates not approved by the company conflicts committee, incurring debt outside the ordinary course of business and disposing of company assets above specified thresholds. The Midkiff/Benedum system is also governed by an operation and expansion agreement with Pioneer which gives system owners having at least a 60% interest in the system the right to approve the annual operating budget and capital investment budget and to impose other limitations on the operation of the system. Thus, a holder of a greater than 40% interest in the system would effectively have a veto right over the operation of the system. Pioneer currently owns an approximate 27% interest in the system.

We are not the operator of the gathering system owned by Laurel Mountain and do not control Laurel Mountain other than through provisions of the limited liability company agreement with Williams Laurel Mountain, LLC, or Williams.

All day-to-day operations of our Appalachia assets (exclusive of Tennessee) are managed by Williams as the operating member of Laurel Mountain. Pursuant to the limited liability company agreement of Laurel Mountain, all decisions of the management committee of Laurel Mountain currently require the unanimous approval of both us and Williams. However, upon the date that any member owns more than 66 $^{2}/_{3}$% of the outstanding ownership interests in Laurel Mountain, which we refer to as the voting change date, specified decisions of the management committee will require the approval of only the holders of a majority of the ownership interests, specified decisions will require the approval of more than 75% of the ownership interests, and specified decisions will require unanimous approval of the membership interests of Laurel Mountain. Dilution of a member s ownership interests can occur when the member does not participate in capital contributions needed to fund specified capital investment projects, in which case the non-pursuing member s ownership interest will be diluted in proportion to the amount of the capital contribution the non-pursuing member would have been required to contribute in connection with such capital investment project. We currently own, through a wholly-owned subsidiary, a 49% interest in Laurel Mountain and have an effective veto on all decisions of the management committee of Laurel Mountain. However, there can be no assurances that we will maintain this ownership percentage or that a voting change date, and the related changes in voting requirements, will not occur.

Tax Risks of Unit Ownership

If we were treated as a corporation for federal income tax purposes, or if we were to become subject to entity-level taxation for federal or state income tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in our anticipated cash flow, likely causing a substantial reduction in the value of our units.

Current law may change, causing us to be treated as a corporation for federal and/or state income tax purposes or otherwise subjecting us to entity level taxation. For example, 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 our unitholders would be reduced.

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

Unitholders may be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability, which results from the taxation of their share of our taxable income.

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

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

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

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect 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 to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect 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.

The sale or exchange of 50% or more of our capital and profits interest within a 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interest in our capital and profits within a 12-month period. The termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income for the year in which the termination occurs. Thus, if this occurs, the unitholder will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to the unitholder with respect to that period.

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We presently anticipate that substantially all of our income will be generated in Oklahoma, Pennsylvania and Texas. Each of those states, except Texas, currently imposes a personal income tax. We may do business or own property in other states in the future. It is the responsibility of each unitholder to file all United States federal, state and local tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

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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 Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely affected, and the costs of any such contest will reduce cash available for distributions to our unitholders.

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 our positions. A court may not agree with some or all of our positions. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which they trade. In addition, we will bear the costs of any contest with the IRS thereby reducing the cash available for distribution to 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

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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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is contained within Item 1, Business.

ITEM 3. LEGAL PROCEEDINGS

We are not subject to any pending material legal proceedings.

ITEM 4: [OMITTED AND RESERVED]

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PART II

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

Our common units are listed on the New York Stock Exchange under the symbol APL. At the close of business on March 2, 2010, the closing price for the common units was $13.32 and there were 109 record holders, one of which is the holder for all beneficial owners who hold in street name.

The following table sets forth the range of high and low sales prices of our common units and distributions declared by quarter per unit on our common limited partner units for the years ended December 31, 2009 and 2008:

	High	Low	Distributions Declared
2009			
Fourth Quarter	$ 10.25	$ 6.55	$ 0.00
Third Quarter	$ 8.31	$ 5.44	$ 0.00
Second Quarter	$ 9.38	$ 3.52	$ 0.00
First Quarter	$ 10.75	$ 2.36	$ 0.15
2008			
Fourth Quarter	$ 26.00	$ 4.68	$ 0.38
Third Quarter	$ 40.03	$ 22.77	$ 0.96
Second Quarter	$ 44.00	$ 37.50	$ 0.96
First Quarter	$ 45.99	$ 38.75	$ 0.94

Subject to the restrictions noted below, our partnership agreement requires that we distribute 100% of available cash to our General Partner and common limited partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

Our General Partner is granted discretion by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When our General Partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common unitholders exceed specified targets, as follows:

Minimum Distributions Per Unit Per Quarter	Percent of Available Cash in Excess of Minimum Allocated to the General Partner
$ 0.42	15%
$ 0.52	25%
$ 0.60	50%

We make distributions of available cash to common unitholders regardless of whether the amount distributed is less than the minimum quarterly distribution. Incentive distributions are generally defined as all

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cash distributions paid to our General Partner that are in excess of 2% of the aggregate amount of cash being distributed. During July 2007, our General Partner, the holder of all of our incentive distribution rights, agreed to allocate a portion of its incentive distribution rights back to us as defined in the IDR Adjustment Agreement. The General Partner s incentive distributions declared for the year ended December 31, 2008, after the allocation of $13.8 million of incentive distribution rights, were $23.5 million. There were no General Partner incentive distributions declared for the year ended December 31, 2009.

On May 29, 2009, we entered into an amendment to our senior secured credit facility (see Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations Term Loan and Revolving Credit Facility) which, among other changes, required that we pay no cash distributions from the time we entered into the amendment through the end of 2009. Commencing with the quarter ending March 31, 2010, cash distributions can be paid only if our senior secured leverage ratio meets certain thresholds and we have minimum liquidity (both as defined in the credit agreement) of at least $50.0 million at the end of the quarter.

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

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ITEM 6. SELECTED FINANCIAL DATA

The following table should be read together with our consolidated financial statements and notes thereto included within Item 8: Financial Statements and Supplementary Data and Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations of this report. We have derived the selected financial data set forth in the table for each of the years ended December 31, 2009, 2008 and 2007 and at December 31, 2009 and 2008 from our consolidated financial statements appearing elsewhere in this report, which have been audited by Grant Thornton LLP, independent registered public accounting firm. We derived the financial data for the years ended December 31, 2006 and 2005 from our consolidated financial statements, which were audited by Grant Thornton LLP and are not included within this report.

The selected financial data set forth in the table include our historical consolidated financial statements, which have been adjusted to reflect the following:

In May 2009, we completed the sale of our NOARK gas gathering and interstate pipeline system (NOARK). In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 205-20-45 Reporting Discontinued Operations, we have retrospectively adjusted our prior period consolidated financial statements to reflect the amounts related to the operations of NOARK as discounted operations; and

The adoption of FASB ASC 810-10-65, Non-Controlling Interest in Consolidated Financial Statements, which clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. FASB also requires consolidated net income to be reported and disclosed on the face of the consolidated statements of operations at amounts that include the amounts attributable to both the parent and the non-controlling interest. We adopted these requirements on January 1, 2009, and have reflected the retrospective application for all periods presented.

The adoption of FASB ASC 260-10-45, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities, which applies to the calculation of earnings per unit (EPU) described in previous guidance for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPU pursuant to the two-class method. We adopted these requirements on January 1, 2009 and have reflected the retroactive application for all periods presented.

FASB ASC 260-10-55, Application of the Two-Class Method, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. It also considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the guidance of FASB ASC, our management believes that the partnership agreement contractually limits cash distributions to available cash and, therefore, undistributed earnings are no longer allocated to the incentive distribution rights. We adopted these requirements on January 1, 2009 and have reflected the retroactive application for all periods presented.

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	Years Ended December 31,				
	2009	2008[(1)]	2007[(1)(2)]	2006[(1)]	2005[(1)(3)]
	(in thousands, except per unit and operating data)				
Statement of operations data:					
Revenue:					
Natural gas and liquids	$ 778,544	$ 1,342,782	$ 739,851	$ 348,504	$ 324,038
Transportation, compression and other fees	32,969	64,489	46,491	36,068	24,773
Equity income in joint venture	4,043				
Gain on asset sale	111,440				
Other income (loss), net	(22,791)	(55,504)	(174,129)	12,024	2,146
Total revenue and other income (loss), net	904,205	1,351,767	612,213	396,596	350,957
Costs and expenses:					
Natural gas and liquids	594,742	1,080,940	576,415	294,142	275,649
Plant operating	58,474	60,835	34,667	15,722	10,557
Transportation and compression	6,657	11,249	6,235	4,946	3,101
General and administrative[(4)]	37,725	(1,838)	59,600	19,127	13,606
Depreciation and amortization	92,434	82,841	43,903	16,759	12,976
Goodwill and other asset impairment loss	10,325	676,860			
Gain on early extinguishment of debt		(19,867)			
Loss on arbitration settlement, net					138
Interest	103,629	85,991	62,592	23,698	13,448
Total costs and expenses	903,986	1,977,011	783,412	374,394	329,475
Income (loss) from continuing operations	219	(625,244)	(171,199)	22,202	21,482
Income from discontinued operations	62,495	20,546	30,830	11,581	5,353
Net income (loss)	62,714	(604,698)	(140,369)	33,783	26,835
(Income) loss attributable to non-controlling interests[(5)]	(3,176)	22,781	(3,940)	(118)	(1,083)
Preferred unit imputed dividend cost		(505)	(2,494)	(1,898)	
Preferred unit dividends	(900)	(1,769)			
Preferred unit dividend effect			(3,756)		
Net income (loss) attributable to common limited partners and the General Partner	$ 58,638	$ (584,191)	$ (150,559)	$ 31,767	$ 25,752
Allocation of net income (loss) attributable to common limited partners and the General Partner:					
Common Limited Partner interest:					
Continuing operations	$ (3,779)	$ (615,583)	$ (193,282)	$ 5,326	$ 12,171
Discontinued operations	61,239	20,133	30,211	11,232	4,184
	57,460	(595,450)	(163,071)	16,558	16,355
General Partner interest:					
Continuing operations	(78)	10,846	11,893	14,978	9,311
Discontinued operations	1,256	413	619	231	86
	1,178	11,259	12,512	15,209	9,397
Net income (loss) attributable to common limited partners and the General Partner:					
Continuing operations	(3,857)	(604,737)	(181,389)	20,304	21,482
Discontinued operations	62,495	20,546	30,830	11,463	4,270
	$ 58,638	$ (584,191)	$ (150,559)	$ 31,767	$ 25,752

Net income (loss) attributable to common limited partners per unit:					
Basic:					
Continuing operations	$ (0.08)	$ (14.43)	$ (7.94)	$ 0.41	$ 1.37
Discontinued operations	1.27	0.47	1.25	0.87	0.47
	$ 1.19	$ (13.96)	$ (6.69)	$ 1.28	$ 1.84

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Diluted[6]:					
Continuing operations	$ (0.08)	$ (14.43)	$ (7.94)	$ 0.41	$ 1.37
Discontinued operations	1.27	0.47	1.25	0.87	0.47
	$ 1.19	$ (13.96)	$ (6.69)	$ 1.28	$ 1.84
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 1,684,384	$ 1,781,011	$ 1,505,319	$ 377,332	$ 319,081
Total assets	2,137,963	2,413,196	2,875,451	786,884	742,726
Total debt, including current portion	1,254,183	1,493,427	1,229,426	324,083	259,625
Total Partners Capital	723,527	650,842	1,271,797	379,134	329,510
Cash flow data:					
Net cash provided by (used in) operating activities	$ 55,853	$ (59,194)	$ 100,444	$ 60,920	$ 33,315
Net cash provided by (used in) investing activities	241,123	(292,944)	(2,024,643)	(104,499)	(409,607)
Net cash provided by (used in) financing activities	(297,400)	341,242	1,935,059	27,028	376,110
Other financial data (unaudited):					
Gross margin [7]	$ 229,752	$ 411,231	$ 263,532	$ 119,891	$ 79,711
EBITDA [8]	269,171	260,887	(21,378)	82,321	52,791
Adjusted EBITDA [8]	244,529	316,548	183,496	87,140	56,509
Maintenance capital expenditures	$ 6,821	$ 6,051	$ 7,659	$ 3,199	$ 1,682
Expansion capital expenditures	148,095	294,672	113,174	75,609	49,071
Total capital expenditures	$ 154,916	$ 300,723	$ 120,833	$ 78,808	$ 50,753
Operating data (unaudited):					
Appalachia:					
Average throughput volumes (MCFD)	104,882	87,299	68,715	61,892	55,204
Mid-Continent:					
Velma system:					
Gathered gas volume (MCFD)	76,378	63,196	62,497	60,682	67,075
Processed gas volume (MCFD)	73,940	60,147	60,549	58,132	62,538
Residue Gas volume (MCFD)	58,350	47,497	47,234	45,466	50,880
NGL volume (BPD)	8,232	6,689	6,451	6,423	6,643
Condensate volume (BPD)	377	280	225	193	256
Elk City/Sweetwater system[9]:					
Gathered gas volume (MCFD)	234,675	280,860	298,200	277,063	250,717
Processed gas volume (MCFD)	213,581	232,664	225,783	154,047	119,324
Residue Gas volume (MCFD)	193,125	210,399	206,721	140,969	109,553
NGL volume (BPD)	11,175	10,487	9,409	6,400	5,303
Condensate volume (BPD)	378	332	212	140	127
Chaney Dell system[10]:					
Gathered gas volume (MCFD)	270,703	276,715	259,270		
Processed gas volume (MCFD)	215,374	245,592	253,523		
Residue Gas volume (MCFD)	228,261	239,498	221,066		
NGL volume (BPD)	13,418	13,263	12,900		
Condensate volume (BPD)	824	791	572		
Midkiff/Benedum system[10]:					
Gathered gas volume (MCFD)	159,568	144,081	147,240		
Processed gas volume (MCFD)	149,656	135,496	141,568		
Residue Gas volume (MCFD)	101,788	92,019	94,281		
NGL volume (BPD)	21,261	19,538	20,618		
Condensate volume (BPD)	1,265	1,142	1,346		

(1)

Restated to reflect amounts reclassified to discontinued operations due to our sale of the NOARK gas gathering and interstate pipeline system

(2) Includes our acquisition of control of a 100% interest in the Chaney Dell natural gas gathering system and processing plants and a 72.8% undivided joint interest in the Midkiff/Benedum natural gas gathering system and processing plants on July 27, 2007, representing approximately five months operations for the year ended December 31, 2007. Operating data for the Chaney Dell and Midkiff/Benedum systems represent 100% of its operating activity.

(3) Includes our acquisition of Elk City on April 14, 2005, representing approximately eight and one-half months operations.

(4) Includes non-cash compensation (income) expense of $0.7 million, ($34.0) million, $36.3 million, $6.3 million and $4.7 million for the years ended December 31, 2009, 2008, 2007, 2006, and 2005, respectively.

(5) For the years ended December 31, 2009, 2008 and 2007, this represents Anadarko s 5% non-controlling interest in the operating results of the Chaney Dell and Midkiff/Benedum systems, which we acquired on July 27, 2007.

(6) For the years ended December 31, 2008, 2007 and 2006, potential common limited partner units issuable upon conversion of our $1,000 par value Class A and Class B cumulative convertible preferred limited partner units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

(7) We define gross margin as revenue less purchased product costs. Purchased product costs include the cost of natural gas and NGLs that we purchase from third parties. Gross margin, as we define it, does not include plant operating and transportation and compression expenses as movements in gross margin generally do not result in directly correlated movements in these cost categories. Plant operating and transportation and compression expenses generally include the costs required to operate and maintain our pipelines and processing facilities, including salaries and wages, repair and maintenance expense, real estate taxes and other overhead costs. Our management views gross margin as an important performance measure of core profitability for our operations and as a key component of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses. The following table reconciles our net income (loss) to gross margin (in thousands):

RECONCILIATION OF GROSS MARGIN

	Years Ended December 31,				
	2009	**2008[1]**	**2007[1][2]**	**2006[1]**	**2005[1][3]**
Net income (loss)	$ 62,714	$ (604,698)	$ (140,369)	$ 33,783	$ 26,835
Adjustments:					
Effect of prior period items[11]				1,090	(1,090)
Equity income in joint venture	(4,043)				
Gain on asset sale	(111,440)				
Other (income) loss, net	22,791	55,504	174,129	(12,024)	(2,146)
Plant operating	58,474	60,835	34,667	15,722	10,557
Transportation and compression	6,657	11,249	6,235	4,946	3,101
General and administrative[5]	37,725	(1,838)	59,600	19,127	13,606
Depreciation and amortization	92,434	82,841	43,903	16,759	12,976
Goodwill and other asset impairment loss	10,325	676,860			
Loss on arbitration settlement, net					138
Interest expense	103,629	85,991	62,592	23,698	13,448
Non-cash linefill loss (gain) [12]	(3,899)	7,797	(2,270)	820	
Unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition[13]			10,423		
Gain on sale of discontinued operations	(51,078)				
NOARK other (income) loss, net[14]	25	15	(26)	(388)	(373)
NOARK transportation and compression[14]	2,089	6,637	7,249	5,807	952
NOARK general and administrative [14]	547	2,255	1,386	3,442	2
NOARK depreciation and amortization[14]	2,773	7,283	7,079	6,235	978
NOARK asset impairment loss[14]		21,648			
NOARK interest[14]	29	(1,148)	(1,066)	874	727
Gross margin	$ 229,752	$ 411,231	$ 263,532	$ 119,891	$ 79,711

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(8) EBITDA represents net income (loss) before net interest expense, income taxes, and depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances, principally to directors and employees, and other cash items such as the non-recurring cash derivative early termination expense (see Item 8: Financial Statements and Supplementary Data Note 12). EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing EBITDA and Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies. The Adjusted EBITDA calculation below is similar to the EBITDA calculation under our credit facility.

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity s financial performance, such as their cost of capital and its tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA and Adjusted EBITDA because they provide investors and management with additional information to better understand our operating performance and are presented solely as a supplemental financial measure. EBITDA and Adjusted EBITDA should not be considered as alternatives to, or more meaningful than, net income or cash flow as determined in accordance with generally accepted accounting principles or as indicators of our operating performance or liquidity. The following table reconciles net income (loss) to EBITDA and EBITDA to Adjusted EBITDA (in thousands):

RECONCILIATION OF EBITDA AND ADJUSTED EBITDA

	Years Ended December 31,				
	2009	**2008(1)**	**2007(1)(2)**	**2006(1)**	**2005(1)(3)**
Net income (loss)	$ 62,714	$ (604,698)	$ (140,369)	$ 33,783	$ 26,835
Adjustments:					
Effect of prior period items(11)				1,090	(1,090)
(Income) loss attributable to non-controlling interests from continuing operations	(3,176)	22,781	(3,940)		
Interest expense	103,629	85,991	62,592	23,698	13,448
Interest rate swap expense in other income (loss), net	443				
Depreciation and amortization	92,434	82,841	43,903	16,759	12,976
Long-lived asset impairment loss	10,325				
Goodwill impairment loss, net of associated non-controlling interest		646,189			
Unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition(13)			10,423		
(Income) loss attributable to non-controlling interests from discontinued operations				(118)	(1,083)
NOARK depreciation and amortization(14)	2,773	7,283	7,079	6,235	978
NOARK asset impairment(14)		21,648			
NOARK interest expense(14)	29	(1,148)	(1,066)	874	727
EBITDA	$ 269,171	$ 260,887	$ (21,378)	$ 82,321	$ 52,791
Adjustments:					
Equity income in joint venture	(4,043)				
Distributions from joint venture	4,310				
Non-cash portion of gain on asset sale(15)	(78,053)				
Non-cash (gain) loss on derivatives	51,342	(115,767)	169,424	(2,316)	(954)
Non-recurring cash derivative early termination expense(16)	5,000	197,641			
Non-cash compensation (income) expense	701	(34,010)	36,306	6,315	4,672
Non-cash line fill loss (gain) (12)	(3,899)	7,797	(2,270)	820	
Other non-cash items(17)			1,414		
Adjusted EBITDA	$ 244,529	$ 316,548	$ 183,496	$ 87,140	$ 56,509

(9) Gathered gas volume for the Elk City/Sweetwater system includes 32,106 MCFD and 11,358 MCFD transferred from the Chaney Dell system for the years ended 2009 and 2008, respectively.

(10) Volumetric data for the Chaney Dell and Midkiff/Benedum systems for the year ended December 31, 2007 represents volumes recorded for the 158-day period from July 27, 2007, the date of our acquisition, through December 31, 2007.

(11) During June 2006, we identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and first quarter of 2006, we recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively.

(12) Includes the non-cash impact of commodity price movements on pipeline linefill.

(13) The acquisition of the Chaney Dell and Midkiff/Benedum systems was consummated on July 27, 2007, although the acquisition s effective date was July 1, 2007. As such, we receive the economic benefits of ownership of the assets as of July 1, 2007. However, in accordance with generally accepted accounting principles, we have only recorded the results of the acquired assets commencing on the closing date of the acquisition. The economic benefits of ownership we received from the acquired assets from July 1 to July 27, 2007 were recorded as a reduction of the consideration paid for the assets.

(14) Included within income from discontinued operations.

(15) For the year ended December 31, 2009, includes the non-cash gain on the sale of assets to the Laurel Mountain joint venture

(16) During the years ended December 31, 2009 and 2008, we made net payments of $5.0 million and $274.0 million, respectively, which resulted in a net cash expense recognized of $5.0 million and $197.6 million, respectively, related to the early termination of derivative contracts that were principally entered into as proxy hedges for the prices received on the ethane and propane portion of our NGL equity volume. These derivative contracts were put into place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. The 2008 settlements were funded through our June 2008 issuance of 5.75 million common limited partner units in a public offering and issuance of 1.39 million common limited partner units to Atlas Pipeline Holdings, L.P. (NYSE: AHD), the owner of our General Partner, and Atlas Energy, Inc. (NASDAQ: ATLS), the parent of Atlas Pipeline Holdings, L.P. s general partner, in a private placement. In connection with this transaction, we also entered into an amendment to our credit facility to revise the definition of Consolidated EBITDA to allow for the add-back of charges relating to the early termination of certain derivative contracts for debt covenant calculation purposes when the early termination of derivative contracts is funded through the issuance of common equity.

(17) Includes the cash proceeds received from the sale of our Enville plant and the non-cash loss recognized within our statements of operations.

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

The following discussion provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with our consolidated financial statements and related notes thereto appearing elsewhere in this report.

General

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. Our principal business objective is to generate cash for distribution to our unitholders. We are a leading provider of natural gas gathering services in the Anadarko and Permian Basins located in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing and treating services in Oklahoma and Texas.

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Mid-Continent and Appalachia.

In our Mid-Continent operations, we own, have interests in and operate eight natural gas processing plants with aggregate capacity of approximately 900 MMCFD and one treating facility with a capacity of approximately 200 MMCFD. These facilities are connected to approximately 9,100 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas, which gathers gas from wells and central delivery points to our natural gas processing and treating plants, as well as third-party pipelines.

Our Appalachia operations are conducted principally through our 49% ownership interest in the Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), which owns and operates approximately 1,800 miles of natural gas gathering systems in the Appalachian Basin located in northeastern Appalachia. We also own and operate approximately 80 miles of active natural gas gathering pipelines in northeastern Tennessee.

On May 31, 2009, we and subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) completed the formation of Laurel Mountain, which currently owns and operates our former Appalachia natural gas gathering system, excluding our northeastern Tennessee operations. Laurel Mountain gathers the majority of the natural gas from wells operated by Atlas Energy Resources, LLC and its subsidiaries (Atlas Energy Resources), a wholly owned subsidiary of Atlas Energy, Inc. (Atlas Energy), a publicly-traded company (NASDAQ: ATLS). Laurel Mountain has natural gas gathering agreements with Atlas Energy Resources, under which Atlas Energy Resources is obligated to pay a gathering fee that is generally the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations).

Recent Events

On January 27, 2009, we and Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, agreed to amend certain terms of our Class A Preferred Units Certificate of Designation. On April 1, 2009, we redeemed 10,000 of the Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $10.0 million, pursuant to the terms of the agreement. On April 13, 2009, we converted 5,000 of the Class A Preferred Units held by Sunlight Capital, at Sunlight Capital s option, into 1,465,653 common limited partner units in accordance with the terms of the agreement. On May 5, 2009, we redeemed the remaining 5,000 Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $5.0 million, pursuant to the terms of the amended preferred units certificate of designation (see Preferred Units).

On March 30, 2009, Atlas Pipeline Holdings, L.P., the parent of our General Partner (AHD), pursuant to its right within the Class B Preferred Unit Purchase Agreement, purchased an additional 5,000 of our 12% Class B Preferred Units of limited partner interest (the Class B Preferred Units) for cash consideration of $1,000 per Class B Preferred Unit (see Preferred Units).

On May 4, 2009, we completed the sale of our NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE: SEP) (Spectra) for net proceeds of $292.0 million in cash, net of working capital adjustments. We received an additional $2.5 million in cash in July 2009 upon the delivery of audited financial statements for the NOARK system assets to Spectra. We used the net proceeds from the transaction to reduce borrowings under our senior secured term loan and revolving credit facility. We have recognized the sale of the NOARK system assets as discontinued operations within our consolidated financial statements.

On May 29, 2009, we entered into an amendment to our credit facility agreement which, among other changes, modified certain financial ratios, limited capital expenditures and required that we pay no cash distributions during the remainder of the year ended December 31, 2009. The amendment allows us to pay cash distributions commencing with the quarter ending March 31, 2010, only if our senior secured leverage ratio meets certain thresholds and we have minimum liquidity (as defined in the credit agreement) of at least $50.0 million (see Term Loan and Revolving Credit Facility).

On May 31, 2009, we and Williams completed the formation of Laurel Mountain, which currently owns and operates our former Appalachia natural gas gathering system, excluding our northeastern Tennessee operations. Williams contribution to Laurel Mountain consisted of cash of $100.0 million, of which we received approximately $87.8 million, net of working capital adjustments, and a note receivable of $25.5 million. We contributed the Appalachia natural gas gathering system and retained a 49% ownership interest in Laurel Mountain, which includes entitlement to preferred distribution rights relating to all payments on the note receivable. Williams obtained the remaining 51% ownership interest in Laurel Mountain. Upon completion of the transaction, we recognized our 49% ownership interest in Laurel Mountain as an investment in joint venture on our consolidated balance sheet at fair value and recognized a gain on sale of $108.9 million, including $54.2 million associated with the revaluation of our investment in Laurel Mountain to fair value. In addition, Atlas Energy Resources sold to Laurel Mountain two natural gas processing plants and associated pipelines located in Southwestern Pennsylvania for $10.0 million. Upon the completion of the transaction, Laurel Mountain entered into new gas gathering agreements with Atlas Energy Resources which superseded the existing natural gas gathering agreements and omnibus agreement between us and Atlas Energy Resources. Under the new gas gathering agreement, Atlas Energy Resources is obligated to pay a gathering fee that is generally the same as the gathering fee required under the terminated agreements, the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations). The new gathering agreements contain additional provisions which define certain obligations and options of each party to build and connect newly drilled wells to any Laurel Mountain gathering system. Our ownership interest in Laurel Mountain has been recognized in accordance with the equity method of accounting within our consolidated financial statements. We used the net proceeds from the transaction to reduce borrowings under our senior secured credit facility.

On July 13, 2009, we sold a natural gas processing facility and a one-third undivided interest in other associated assets located in our Mid-Continent operating segment for approximately $22.6 million in cash. The facility was sold to Penn Virginia Resource Partners, L.P. (NYSE: PVR), who will provide natural gas volumes to the facility and reimburse us for its proportionate share of the operating expenses. We will continue to operate the facility. We used the proceeds from this transaction to reduce outstanding borrowings under our senior secured credit facility. We recognized a gain on sale of $2.5 million, which is recorded within gain on asset sales on our consolidated statements of operations.

On August 17, 2009, we sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. We also received a capital contribution from AHD of $0.4 million for AHD to maintain its 2.0% general partner interest in us. In addition, we issued warrants granting investors in our private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and revolving credit facility (see Term Loan and Revolving Credit Facility), and we made similar repayments with net proceeds from exercise of the warrants. In January 2010, we amended the warrants to purchase 2,689,765 common units and all warrants were exercised (see Subsequent Events).

On November 2, 2009, our agreement with Pioneer Natural Resources Company (Pioneer), whereby Pioneer had options to purchase up to an additional 22.0% interest in the Mid-Continent s Midkiff/Benedum system expired.

Subsequent Events

On January 7, 2010, we executed amendments to warrants to purchase 2,689,765 of our common units. The warrants were originally issued along with our common units in connection with a private placement to institutional investors that closed on August 20, 2009. The common units and warrants were issued and sold in a transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and credit facility (see Term Loan and Credit Facility).

Significant Acquisitions

From the date of our initial public offering in January 2000 through December 2009, we have completed seven acquisitions at an aggregate cost of approximately $2.4 billion, including, most recently in July 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas gathering systems and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). At the date of acquisition, the Chaney Dell system included 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum system included 2,500 miles of gathering pipeline and two processing plants. The transaction was accomplished through the formation of two joint venture companies which own the respective systems, to which we contributed $1.9 billion and Anadarko contributed the Anadarko Assets. We funded the purchase price in part from $1.125 billion in proceeds we received from our private placement of our common units to investors at a negotiated purchase price of $44.00 per unit.

Of the $1.125 billion, $168.8 million of these units were purchased by Atlas Pipeline Holdings, the parent of our General Partner. Our General Partner, which holds all of our incentive distribution rights, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter (the IDR Adjustment Agreement) (see Partnership Distributions). We funded the remaining purchase price from $830.0 million of proceeds from a senior secured term loan which matures in July 2014 and borrowings under our senior secured revolving credit facility that matures in July 2013 (see Term Loan and Credit Facility). Our General Partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the General Partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter (see Partnership Distributions).

In connection with this acquisition, we reached an agreement with Pioneer, which currently holds an approximate 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer had options to buy up to an additional 22% interest in the Midkiff/Benedum system. These options expired on November 2, 2009.

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Contractual Revenue Arrangements

Our principal revenue is generated from the gathering and sale of natural gas and NGLs. Variables that affect our revenue are:

- the volumes of natural gas we gather and process which, in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas they produce, and the demand for natural gas and NGLs;
- the price of the natural gas we gather and process and the NGLs we recover and sell, which is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States;
- the NGL and BTU content of the gas that is gathered and processed;
- the contract terms with each producer; and
- the efficiency of our gathering systems and processing plants

Revenue consists of the fees earned from our gathering and processing operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems and then sell the natural gas and NGLs off of delivery points on our systems. Under other agreements, we gather natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas. Our revenue is a function of the volume of natural gas that we gather and process and is not directly dependent on the value of the natural gas. We are also paid a separate compression fee on many of our systems. The fee is dependent upon the volume of gas flowing through our compressors and the quantity of compression stages utilized to gather the gas.

Percentage of Proceeds (POP) Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, with the remainder being remitted to the producer. In this contract-type, we and the producer are directly dependent on the volume of the commodity and its value; we effectively own a percentage of the commodity and revenues are directly correlated to its market value. POP Contracts may include a fee component which is charged to the producer.

Keep-Whole Contracts. These contracts require us, as the processor and gatherer, to gather or purchase raw natural gas at current market rates. The volume of gas gathered or purchased is based on the measured volume at an agreed upon location (generally at the wellhead). The volume of gas redelivered or sold at the tailgate of our processing facility will be lower than the volume purchased at the wellhead primarily due to BTUs extracted when processed through a plant. Therefore, we bear the economic risk (the processing margin risk) that (i) the volume of Residue Gas available for redelivery to the producer may be less than we received from the producer; or (ii) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas (plus, in either case, the cost of the natural gas we must purchase to return an equivalent volume, measured in BTU content, to producers to keep them whole with respect to their original measured volume). In order to help mitigate the risk associated with Keep-Whole contracts we generally impose a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under Keep-Whole agreements is often lower in BTU content and thus, can meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods of margin risk.

In our Appalachia segment, substantially all of the natural gas we gather via Laurel Mountain is for Atlas Energy Resources under contracts in which Laurel Mountain earns a fee equal to a percentage, generally 16%, of the gross sales price for natural gas, inclusive of the effects of financial and physical hedging, subject, in most cases, to a minimum of $0.35 per thousand cubic feet, or MCF, depending on the ownership of the well. The balance of the natural gas gathered by Laurel Mountain and our Tennessee operations is for third-party operators generally under fixed-fee contracts.

Recent Trends and Uncertainties

The midstream natural gas industry links the exploration and production of natural gas and the delivery of its components to end-use markets and provides natural gas gathering, compression, dehydration, treating, conditioning, processing, fractionation and transportation services. This industry group is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

We face competition in obtaining natural gas supplies for our processing and related services operations. Competition for natural gas supplies is based primarily on the location of gas-gathering facilities and gas-processing plants, operating efficiency and reliability, and the ability to obtain a satisfactory price for products recovered. Competition for customers is based primarily on price, delivery capabilities, quality of assets, flexibility, service history and maintenance of high-quality customer relationships. Many of our competitors operate as master limited partnerships and enjoy a cost of capital comparable to and, in some cases lower than, ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas. We believe the primary difference between us and some of our competitors is that we provide an integrated and responsive package of midstream services, while some of our competitors provide only certain services. We believe that offering an integrated package of services, while remaining flexible in the types of contractual arrangements that we offer producers, allows us to compete more effectively for new natural gas supplies in our regions of operations.

As a result of our POP and Keep-Whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas and NGLs. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. However, energy market uncertainty has negatively impacted North American drilling activity in the recent past. Lower drilling levels and shut-in wells over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. Average estimated unhedged 2010 market prices for NGLs, natural gas and condensate, based upon New York Mercantile Exchange (NYMEX) forward price curves as of February 15, 2010, are $1.10 per gallon, $5.71 per MMBTU and $76.26 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended December 31, 2010 by approximately $27.2 million.

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Currently, there is an extremely significant level of uncertainty in the financial markets. This uncertainty presents additional potential risks to us. These risks include the availability and costs associated with our borrowing capabilities and raising additional capital, and an increase in the volatility of the price of our common units. While we have no definitive plans to access the capital markets, should we decide to do so in the near future, the terms, size, and cost of new debt or equity could be less favorable than in previous transactions.

Results of Operations

The following table illustrates selected volumetric information related to our reportable segments for the periods indicated:

	Years Ended December 31,		
	2009	**2008**	**2007**
Operating data:			
Appalachia:			
Average throughput volumes (MCFD)	104,882	87,299	68,715
Mid-Continent:			
Velma system:			
Gathered gas volume (MCFD)	76,378	63,196	62,497
Processed gas volume (MCFD)	73,940	60,147	60,549
Residue Gas volume (MCFD)	58,350	47,497	47,234
NGL volume (BPD)	8,232	6,689	6,451
Condensate volume (BPD)	377	280	225
Elk City/Sweetwater system(1):			
Gathered gas volume (MCFD)	234,675	280,860	298,200
Processed gas volume (MCFD)	213,581	232,664	225,783
Residue Gas volume (MCFD)	193,125	210,399	206,721
NGL volume (BPD)	11,175	10,487	9,409
Condensate volume (BPD)	378	332	212
Chaney Dell system(2):			
Gathered gas volume (MCFD)	270,703	276,715	259,270
Processed gas volume (MCFD)	215,374	245,592	253,523
Residue Gas volume (MCFD)	228,261	239,498	221,066
NGL volume (BPD)	13,418	13,263	12,900
Condensate volume (BPD)	824	791	572
Midkiff/Benedum system(2):			
Gathered gas volume (MCFD)	159,568	144,081	147,240
Processed gas volume (MCFD)	149,656	135,496	141,568
Residue Gas volume (MCFD)	101,788	92,019	94,281
NGL volume (BPD)	21,261	19,538	20,618
Condensate volume (BPD)	1,265	1,142	1,346

(1) Gathered gas volume for the Elk City/Sweetwater system includes 32,106 MCFD and 11,358 MCFD transferred from the Chaney Dell system for the years ended 2009 and 2008, respectively.

(2) Volumetric data for the Chaney Dell and Midkiff/Benedum systems for the year ended December 31, 2007 represents volumes recorded for the 158-day period from July 27, 2007, the date of acquisition, through December 31, 2007.

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Financial Presentation

On May 4, 2009, we completed the sale of our NOARK gas gathering and interstate pipeline system. As such, we have adjusted the prior period consolidated financial information presented to reflect the amounts related to the operations of the NOARK gas gathering and interstate pipeline system as discontinued operations.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenue. The following table details the variances between the years ended 2009 and 2008 for revenues (in thousands):

	Years Ended December 31, 2009	2008	Variance	Percent Variance
Revenues:				
Natural gas and liquids	$ 778,544	$ 1,342,782	$ (564,238)	(42.0)%
Transportation, compression and other fee revenue	32,969	64,489	(31,520)	(48.9)%
Equity income in joint venture	4,043		4,043	N/A
Gain on asset sale	111,440		111,440	N/A
Other loss, net	(22,791)	(55,504)	32,713	58.9%
Total Revenues	$ 904,205	$ 1,351,767	$ (447,562)	(33.1)%

Natural gas and liquids revenue was $778.5 million for the year ended December 31, 2009, a decrease of $564.2 million from $1,342.8 million for the prior year. The decrease was primarily attributable to decreases in production revenue from the Chaney Dell system of $223.6 million, the Midkiff/Benedum system of $141.8 million, the Elk City/Sweetwater system of $108.5 million and the Velma system of $87.2 million, which were all impacted by lower average commodity prices and changes in volumes in comparison to the prior year.

Processed natural gas volume on the Chaney Dell system was 215.4 MMCFD for the year ended December 31, 2009, a decrease of 12.3% compared to 245.6 MMCFD for the prior year, partially due to shut-in wells as a result of lower gas prices. The Chaney Dell system increased its NGL production volume for the year ended December 31, 2009 by 1.2% when compared to the prior year to 13,418 BPD, representing an increase in production efficiency. The Midkiff/Benedum system had processed natural gas volume of 149.7 MMCFD for the year ended December 31, 2009, an increase of 10.5% compared to 135.5 MMCFD for the prior year. The Midkiff/Benedum system increased its NGL production volume for the year ended December 31, 2009 by 8.8% when compared to the prior year to 21,261 BPD, representing an increase in production efficiency, partially due to the start-up of the new Consolidator plant. Processed natural gas volume averaged 73.9 MMCFD on the Velma system for the year ended December 31, 2009, an increase of 22.9% from the prior year, mainly due to the new gathering line from the Madill area. The Velma system increased its NGL production volume for the year ended December 31, 2009 by 23.1% when compared to the prior year to 8,232 BPD, primarily due to the additional gas processed. Processed natural gas volume on the Elk City/Sweetwater system averaged 213.6 MMCFD for the year ended December 31, 2009, a decrease of 8.2% from the prior year as a result of shut-in wells due to lower gas prices. NGL production volume for the Elk City/Sweetwater system was 11,175 BPD, an increase of 6.6% from the prior year, as production efficiency of the processing plants has increased. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 7A: Quantitative and Qualitative Disclosures About Market Risk.

Transportation, compression and other fee revenue decreased to $33.0 million for the year ended December 31, 2009 compared with $64.5 million for the prior year. This $31.5 million decrease was primarily due to a $26.2 million decrease from the Appalachia system and a $4.7 million decrease from the Chaney Dell system. The decrease from the Appalachia system was a result of our May 2009 contribution of the majority of the system to Laurel Mountain, a joint venture in which we have a 49% ownership interest, after which we have recognized our ownership interest in the net income of Laurel Mountain as equity income on our consolidated statements of operations. The decrease from the Chaney Dell system was due to lower fee-based volumes.

Equity income of $4.0 million for the year ended December 31, 2009 represents our ownership interest in the net income of Laurel Mountain for the period from its formation on May 31, 2009 through December 31, 2009.

Gain on asset sales of $111.4 million for the year ended December 31, 2009 represents the gain recognized on our sale of a 51% ownership interest in our Appalachia natural gas gathering system of $108.9 million and the $2.5 million gain recognized on our sale of the natural gas processing facility (see Recent Events).

Other loss, net, including the impact of certain gains and losses recognized on derivatives, was a loss of $22.8 million for the year ended December 31, 2009, which represents a favorable movement of $32.7 million from the prior year loss of $55.5 million. This favorable movement was due primarily to a $195.0 million favorable variance of net cash derivative expense related to the early termination of a portion of our derivative contracts (see Item 8: Financial Statements and Supplementary Data Note 12) and an $84.1 million favorable movement in non-cash derivative gains related to the early termination of a portion of our derivative contracts, partially offset by an unfavorable movement of $214.5 million in non-cash mark-to-market adjustments on derivatives and a $37.0 million unfavorable movement related to cash settlements on non-qualified derivatives. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 7A: Quantitative and Qualitative Disclosures About Market Risk.

Costs and Expenses. The following table details the variances between the years ended 2009 and 2008 for costs and expenses (in thousands):

	Years Ended December 31, 2009	2008	Variance	Percent Variance
Costs and Expenses:				
Natural gas and liquids	$ 594,742	$ 1,080,940	$ (486,198)	(45.0)%
Plant operating	58,474	60,835	(2,361)	(3.9)%
Transportation and compression	6,657	11,249	(4,592)	(40.8)%
General and administrative	37,725	(1,838)	39,563	2,152.5%
Depreciation and amortization	92,434	82,841	9,593	11.6%
Goodwill and other asset impairment loss	10,325	676,860	(666,535)	(98.5)%
Interest expense	103,629	85,991	17,638	20.5%
Gain on early extinguishment of debt		(19,867)	19,867	100.0%
Total Costs and Expenses	$ 903,986	$ 1,977,011	$ (1,073,025)	(54.3)%

Natural gas and liquids cost of goods sold of $594.7 million for the year ended December 31, 2009 represented a decrease of $486.2 million from the prior year due primarily to a decrease in average commodity prices and changes in volumes in comparison to the prior year, as discussed above in revenues. Plant operating expenses of $58.5 million for the year ended December 31, 2009 represented a decrease of $2.4 million from the prior year due primarily to a $2.7 million decrease associated with the Chaney Dell system resulting from lower operating and maintenance costs. Transportation and compression expenses decreased to $6.7 million for the year ended December 31, 2009 compared with $11.2 million for the prior year due to our contribution of the Appalachia system to Laurel Mountain.

General and administrative expense, including amounts reimbursed to affiliates, increased $39.6 million to $37.7 million for the year ended December 31, 2009 compared with $1.8 million income for the prior year.

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The increase was primarily related to a $34.7 million increase in non-cash compensation expense primarily due to a $36.3 million net mark-to-market gain recognized during the year ended December 31, 2008 principally associated with the vesting of certain common unit awards that were based on the financial performance of certain assets during 2008. The mark-to-market gain was the result of a significant change in our common unit market price at December 31, 2008 when compared with the December 31, 2007 price, which was utilized in the estimate of the non-cash compensation expense for these awards. These common unit awards were issued during the year ended December 31, 2009.

Depreciation and amortization increased to $92.4 million for the year ended December 31, 2009 compared with $82.8 million for the year ended December 31, 2008 due primarily to our expansion capital expenditures incurred subsequent to December 31, 2008.

Interest expense increased to $103.6 million for the year ended December 31, 2009 as compared with $86.0 million for the prior year. This $17.6 million increase was primarily due to a $8.5 million increase in interest expense related to our additional senior notes issued during June 2008 (see Senior Notes), a $9.1 million increase in interest expense associated with outstanding borrowings on our revolving credit facility, and a $2.1 million increase in the amortization of deferred finance costs due principally to accelerated amortization associated with the retirement of a portion of our term loan with the proceeds from the sale of our NOARK system, partially offset by a $5.9 million decrease in interest expense associated with our senior secured term loan primarily due to the repayment of $273.7 million of indebtedness since December 2008 (see Term Loan and Revolving Credit Facility) and lower unhedged interest rates.

Goodwill and other asset impairment loss decreased to $10.3 million for the year ended December 31, 2009 as compared with $676.9 million for the year ended December 31, 2008. The $10.3 million impairment was due to an impairment of certain gas plant and gathering assets as a result of our annual review of long-lived assets. The $676.9 million impairment loss for the year ended December 31, 2008 was due to an impairment charge to our goodwill from the reduction of our estimate of the fair value of goodwill in comparison to its carrying amount at December 31, 2008. The estimate of fair value of goodwill was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. There were no goodwill impairments for the year ended December 31, 2009.

Gain on early extinguishment of debt of $19.9 million for the year ended December 31, 2008 resulted from our repurchase of approximately $60.0 million of our Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million of our 8.125% Senior Notes and approximately $27.0 million of our 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue.

The following table details the variances between the years ended 2009 and 2008 for Discontinued Operations and (Gain) loss attributable to non-controlling interests (in thousands):

	Years Ended December 31, 2009	2008	Variance	Percent Variance
Income from discontinued operations	$ 62,495	$ 20,546	$ 41,949	204.2%
(Income) loss attributable to non-controlling interests	(3,176)	22,781	(25,957)	(113.9)%

Income from discontinued operations, which consists of amounts associated with the NOARK gas gathering and interstate pipeline system we sold in May 2009, was $62.5 million for the year ended December 31, 2009 compared with $20.5 million for the prior year. The increase was due to a $51.1 million gain recognized on the sale of the NOARK system, partially offset by a $9.1 million decrease in the operating results of the NOARK system due to its sale in May 2009.

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Income attributable to non-controlling interests was $3.2 million for the year ended December 31, 2009 compared with loss attributable to non-controlling interests of $22.8 million for the prior year. This change was primarily due to higher net income for the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to accomplish our acquisition of control of the respective systems. The increase in net income of the Chaney Dell and Midkiff/Benedum joint ventures was principally due to the goodwill impairment charge in 2008 of $613.4 million for the goodwill originally recognized upon acquisition of these systems. The non-controlling interest expense represents Anadarko s 5% interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenue. The following table details the variances between the years ended 2008 and 2007 for revenues (in thousands):

	Years Ended December 31, 2008	2007	Variance	Percent Variance
Revenues:				
Natural gas and liquids	$ 1,342,782	$ 739,851	$ 602,931	81.5%
Transportation, compression and other fee revenue	64,489	46,491	17,998	38.7%
Other loss, net	(55,504)	(174,129)	118,625	68.1%
Total Revenues	$ 1,351,767	$ 612,213	$ 739,554	120.8%

Natural gas and liquids revenue was $1,342.8 million for the year ended December 31, 2008, an increase of $602.9 million from $739.9 million for the prior year. The increase was primarily attributable to an increase in revenue contribution from the Chaney Dell and Midkiff/Benedum systems, which we acquired in July 2007, of $512.8 million, and an increase from the Velma and Elk City/Sweetwater systems of $26.6 million and $61.8 million, respectively, due primarily to higher average commodity prices over the full year and an increase in volumes. Processed natural gas volume on the Chaney Dell system was 245.6 MMCFD for the year ended December 31, 2008, a decrease of 3.1% compared to 253.5 MMCFD for the period from its July 2007 acquisition to December 31, 2007. The Midkiff/Benedum system had processed natural gas volume of 135.5 MMCFD for the year ended December 31, 2008, a decrease of 4.3% compared to 141.6 MMCFD for the period from its July 2007 acquisition to December 31, 2007 due to the adverse effects of a hurricane which struck the surrounding area in September 2008. Processed natural gas volume averaged 60.1 MMCFD on the Velma system for the year ended December 31, 2008, a decrease of 0.7% from the prior year. However, the Velma system increased its NGL production volume by 3.7% when compared to the prior year to 6,689 BPD for the year ended December 31, 2008, representing an increase in production efficiency. Processed natural gas volume on the Elk City/Sweetwater system averaged 232.7 MMCFD for the year ended December 31, 2008, an increase of 3.0% from the prior year. NGL production volume for the Elk City/Sweetwater system was 10,487 BPD, an increase of 11.5% from the prior year, as production efficiency of the processing plants has increased. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives in Item 8 Financial Statements and Supplementary Data Note 12.

Transportation, compression and other fee revenue increased to $64.5 million for the year ended December 31, 2008 compared with $46.5 million for the prior year. This $18.0 million increase was primarily due to an $11.0 million increase from the Appalachia system due to higher throughput volume and a higher average transportation rate, $5.4 million of a full year s contributions from the Chaney Dell and Midkiff/Benedum systems, and an increase of $1.7 million associated with the Elk City/Sweetwater system. The Appalachia system s average throughput volume was 87.3 MMCFD for the year ended December 31, 2008 as compared with 68.7 MMCFD for the prior year, an increase of 18.6 MMCFD or 27.0%. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system, the acquisition of the McKean processing plant and gathering system in central Pennsylvania for $6.1 million in August 2007, and the acquisition of the Vinland processing plant and gathering system in northeastern Tennessee for $9.1 million in February 2008.

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Other loss net, including the impact of certain gains and losses recognized on derivatives, was a loss of $55.5 million for the year ended December 31, 2008, which represents a favorable movement of $118.6 million from the prior year loss of $174.1 million. This favorable movement was due primarily to a $356.8 million favorable movement in non-cash mark-to-market adjustments on derivatives, partially offset by a net cash loss of $200.0 million and a non-cash derivative loss of $39.2 million related to the early termination of a portion of our derivative contracts (see Recent Events), and an unfavorable movement of $1.5 million related to cash settlements on derivatives that were not designated as hedges. The $356.8 million favorable movement in non-cash mark-to-market adjustments on derivatives was due principally to a decrease in forward crude oil market prices from December 31, 2007 to December 31, 2008 and their favorable mark-to-market impact on certain non-hedge derivative contracts we have for production volumes in future periods. For example, average forward crude oil prices, which are the basis for adjusting the fair value of our crude oil derivative contracts, at December 31, 2008, were $56.94 per barrel, a decrease of $32.95 per barrel from average forward crude oil market prices at December 31, 2007 of $89.89 per barrel. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 7A: Quantitative and Qualitative Disclosures About Market Risk.

Costs and Expenses. The following table details the variances between the years ended 2008 and 2007 for costs and expenses (in thousands):

	Years Ended December 31, 2008	2007	Variance	Percent Variance
Costs and Expenses:				
Natural gas and liquids	$ 1,080,940	$ 576,415	$ 504,525	87.5%
Plant operating	60,835	34,667	26,168	75.5%
Transportation and compression	11,249	6,235	5,014	80.4%
General and administrative	(1,838)	59,600	(61,438)	(103.1)%
Depreciation and amortization	82,841	43,903	38,938	88.7%
Goodwill and other asset impairment loss	676,860		676,860	N/A
Interest expense	85,991	62,592	23,399	37.4%
Gain on early extinguishment of debt	(19,867)		(19,867)	N/A
Total Costs and Expenses	$ 1,977,011	$ 783,412	$ 1,193,599	152.4%

Natural gas and liquids cost of goods sold of $1,080.9 million and plant operating expenses of $60.8 million for the year ended December 31, 2008 represented increases of $504.5 million and $26.2 million, respectively, from the prior year amounts due primarily to an increase of $453.2 million in natural gas and liquids cost of goods sold and a $23.0 million increase in plant operating expenses from a full year s contribution from the Chaney Dell and Midkiff/Benedum systems, and higher average commodity prices for the full year and an increase in production volume on the Velma and Elk City/Sweetwater systems. Transportation and compression expenses increased $5.0 million to $11.2 million for the year ended December 31, 2008 due to an increase in Appalachia system operating and maintenance costs as a result of increased capacity, additional well connections and operating costs of the McKean and Vinland processing plants and gathering systems.

General and administrative expense (income), including amounts reimbursed to affiliates, decreased $61.4 million to income of $1.8 million for the year ended December 31, 2008 compared with expense of $59.6 million for the prior year. The decrease was primarily related to a $70.3 million decrease in non-cash compensation expense, partially offset by higher costs of managing our operations, including the Chaney Dell and Midkiff/Benedum systems acquired in July 2007 and capital-raising and strategic activities. The decrease in non-cash compensation expense was principally attributable to a $36.3 million gain recognized during the year ended December 31, 2008 in comparison to an expense of $33.4 million for the prior year for certain common unit awards for which the ultimate amount issued was determined after the completion of our 2008 fiscal year and was based upon the financial performance of certain acquired assets (see Item 8: Financial Statements and Supplementary Data Note 17). The gain was the result of a significant change in our common unit market price at December 31, 2008 when compared with the December 31, 2007 price, which was utilized in the estimate of the non-cash compensation expense for these awards, and lower financial performance of the certain assets acquired in comparison to estimated performance.

Depreciation and amortization increased to $82.8 million for the year ended December 31, 2008 compared with $43.9 million for the year ended December 31, 2007 due primarily to the depreciation associated with our Chaney Dell and Midkiff/Benedum acquired assets and our expansion capital expenditures incurred subsequent to December 31, 2007.

Interest expense increased to $86.0 million for the year ended December 31, 2008 as compared with $62.6 million for the prior year. This $23.4 million increase was primarily due to a $14.7 million increase in interest expense associated with the term loan issued in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems (see Term Loan and Credit Facility) and $11.1 million of interest expense related to our additional senior notes issued during June 2008.

Goodwill and other asset impairment loss of $676.9 million for the year ended December 31, 2008 was due to an impairment charge to our goodwill as a result of our annual goodwill impairment test. The goodwill impairment resulted from the reduction of our estimate of the fair value of goodwill in comparison to its carrying amount at December 31, 2008. The estimate of fair value of goodwill was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. There were no goodwill impairments for the year ended December 31, 2007.

Gain on early extinguishment of debt of $19.9 million for the year ended December 31, 2008 resulted from our repurchase of approximately $60.0 million of our Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million of our 8.125% Senior Notes and approximately $27.0 million of our 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue.

The following table details the variances between the years ended 2008 and 2007 for Discontinued Operations and (Gain) loss attributable to non-controlling interests (in thousands):

	Years Ended December 31,			Percent
	2008	2007	Variance	Variance
Income from discontinued operations	$ 20,546	$ 30,830	$ (10,284)	(33.4)%
(Income) loss attributable to non-controlling interests	22,781	(3,940)	26,721	678.2%

Income from discontinued operations consists of amounts associated with the NOARK gas gathering and interstate pipeline system, which we sold on May 4, 2009. Income from discontinued operations decreased to $20.5 million for the year ended December 31, 2008 compared with $30.8 million for the prior year. The decrease was due primarily to a $21.6 million write-off of costs related to a pipeline expansion project, partially offset by an increase of $5.9 million for natural gas and liquids revenue. The write-off of costs incurred consisted of preliminary construction and engineering costs as well as a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

Loss attributable to non-controlling interests was $22.8 million for the year ended December 31, 2008 compared with income attributable to non-controlling interests of $3.9 million for the prior year. This change was primarily due to lower net income for the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to accomplish our acquisition of control of the respective systems. The decrease in net income of the

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Chaney Dell and Midkiff/Benedum joint ventures was principally due to the goodwill impairment charge of $613.4 million for the goodwill originally recognized upon acquisition of these systems. The non-controlling interest expense represents Anadarko s 5% interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash generated from operations and borrowings under our credit facility. Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and quarterly distributions to our common unitholders and General Partner. In general, we expect to fund:

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through the retention of cash and additional borrowings; and
- debt principal payments through operating cash flows and additional borrowings as they become due or by the issuance of additional limited partner units or asset sales.

At December 31, 2009, we had $326.0 million of outstanding borrowings under our $380.0 million senior secured credit facility and $10.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $43.9 million of remaining committed capacity under the credit facility, subject to covenant limitations (see Term Loan and Revolving Credit Facility). We were in compliance with the credit facility s covenants at December 31, 2009. At December 31, 2009, we had a working capital deficit of $30.6 million compared with a $48.8 million working capital deficit at December 31, 2008. 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 need to supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

Recent instability in the financial markets, as a result of recession or otherwise, has increased the cost of capital while the availability of funds from those markets has diminished. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to the extent required and on acceptable terms.

Cash Flows Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The following table details the variances between the years ended 2009 and 2008 for cash flows (in thousands):

	Years Ended December 31,			Percent
	2009	**2008**	**Variance**	**Variance**
Net cash provided by (used in) operating activities	$ 55,853	$ (59,194)	$ 115,047	194.4%
Net cash provided by (used in) investing activities	241,123	(292,944)	534,067	182.3%
Net cash provided by (used in) financing activities	(297,400)	341,242	(638,642)	(187.2)%
Net change in cash and cash equivalents	$ (424)	$ (10,896)	$ 10,472	96.1%

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Net cash provided by operating activities of $55.9 million for the year ended December 31, 2009 represented an increase of $115.1 million from $59.2 million of net cash used in operating activities for the prior year. The increase was derived from a $165.7 million favorable movement in net earnings from continuing operations excluding non-cash charges, partially offset by a $22.0 million decrease in cash flows from working capital changes and a $28.6 million decrease in cash provided by discontinued operations. The increase in net earnings from continuing operations excluding non-cash charges was principally due to a $195.0 million favorable variance of net cash derivative expense related to the early termination of a portion of our derivative contracts (see Item 8: Financial Statements and Supplementary Data Note 12).

Net cash provided by investing activities was $241.1 million for the year ended December 31, 2009, an increase of $534.1 million from $292.9 million of net cash used in investing activities for the prior year. This increase was principally due to a $315.8 million increase in cash provided by discontinued operations, the net proceeds of $112.0 million received from the sale of our Appalachia system assets and a natural gas processing facility and a $145.8 million decrease in capital expenditures, partially offset by a 2008 receipt of a $30.2 million cash reimbursement for state sales tax paid on our 2007 transaction to acquire the Chaney Dell and Midkiff/Benedum systems and a 2008 period receipt of $1.3 million in connection with a post-closing purchase price adjustment of our 2007 acquisition of the Chaney Dell and Midkiff/Benedum systems (see further discussion of capital expenditures under Liquidity and Capital Resources Capital Requirements).

Net cash used in financing activities was $297.4 million for the year ended December 31, 2009, a decrease of $638.6 million from $341.2 million of net cash provided by financing activities for the prior year. This decrease was principally due to the absence in the current period of $244.9 million of net proceeds from the issuance of 8.75% Senior Notes during June 2008 (see Senior Notes), a decrease of $240.9 million of net proceeds from the issuance of our common units, and a $173.0 million net decrease in borrowings under our revolving credit facility.

Cash Flows Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

The following table details the variances between the years ended 2008 and 2007 for cash flows (in thousands):

	Years Ended December 31,			Percent
	2008	**2007**	**Variance**	**Variance**
Net cash provided by (used in) operating activities	$ (59,194)	$ 100,444	$ (159,638)	(158.9)%
Net cash used in investing activities	(292,944)	(2,024,643)	1,731,699	85.5%
Net cash provided by financing activities	341,242	1,935,059	(1,593,817)	(82.4)%
Net change in cash and cash equivalents	$ (10,896)	$ 10,860	$ (21,756)	(200.3)%

Net cash used in operating activities of $59.2 million for the year ended December 31, 2008 represented a decrease of $159.6 million from $100.4 million of net cash provided by operating activities for the prior year. The decrease was derived principally from a $208.9 million unfavorable movement in net income (loss) excluding non-cash charges, partially offset by a $43.9 million increase in cash flows from working capital changes and a $6.7 million increase in cash provided by our discontinued operations. The decrease in net income (loss) excluding non-cash charges was principally due to the $197.6 million net unfavorable cash impact from the early termination of certain derivative instruments during the year ended December 31, 2008.

Net cash used in investing activities was $292.9 million for the year ended December 31, 2008, a decrease of $1,731.7 million from $2,024.6 million for the prior year. This decrease was principally due to a $1,915.9 million decrease in net cash paid for acquisitions, partially offset by a $179.9 million increase in capital expenditures and a $6.3 million increase in cash used in our discontinued operations. Net cash paid for acquisitions of $1,884.5 million in 2007 represents the net amount paid for our acquisition of the Chaney Dell and Midkiff/Benedum systems. The $31.4 million of net cash received for acquisition in the current period principally represents the reimbursement of state sales tax initially paid for our prior year acquisition of the Chaney Dell and Midkiff/Benedum systems (see further discussion of capital expenditures under Liquidity and Capital Resources Capital Requirements).

Net cash provided by financing activities was $341.2 million for the year ended December 31, 2008, a decrease of $1,593.9 million from $1,935.1 million for the prior year. This decrease was principally due to an $858.2 million decrease from the net proceeds of issuance of our common units, a $572.3 million decrease from the net proceeds of issuance of long-term debt, a $162.9 million increase in repayments of long-term debt, and a $107.4 million increase in cash distributions to common limited partners and the General Partner, partially offset by a $130.0 million increase in borrowings under our revolving credit facility. The decrease in net proceeds of issuance of our common units and long-term debt were due to the prior year financing of our acquisition of the Chaney Dell and Midkiff/Benedum systems. The repayments of long-term debt were associated with our issuance of $250.0 million 8.75% Senior Notes in June 2008, the net proceeds of which were utilized to repay indebtedness under our senior secured term loan and revolving credit facility and our repurchase of approximately $60.0 million in face amount of our Senior Notes for an aggregate purchase price of approximately $40.1 million during the year ended December 31, 2008. The increase in net borrowings under our revolving credit facility was principally utilized to finance our capital expenditures during the period.

Capital Requirements

Our operations require continual investment to upgrade or enhance existing operations and to ensure compliance with safety, operational, and environmental regulations. Our capital requirements consist primarily of:

- maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and

- expansion capital expenditures to acquire complementary assets and to expand the capacity of our existing operations.

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

	Years Ended December 31,		
	2009	**2008**	**2007**
Maintenance capital expenditures	$ 6,821	$ 6,051	$ 7,659
Expansion capital expenditures	148,095	294,672	113,174
Total	$ 154,916	$ 300,723	$ 120,833

Expansion capital expenditures decreased to $148.1 million for the year ended December 31, 2009 due principally to construction of a 60 MMCFD expansion of our Sweetwater processing plant and the construction of the Madill to Velma pipeline during the prior year, decreases in capital expenditures related to the sale of the NOARK system and a 49% ownership interest in the Appalachia system. The increase in maintenance capital expenditures for the year ended December 31, 2009 when compared with the prior year was due to fluctuations in the timing of our scheduled maintenance activity. As of December 31, 2009, we have approved expenditures of approximately $12.8 million on well connects, pipeline extensions, compressor station upgrades and processing facility upgrades.

Expansion capital expenditures increased to $294.7 million for the year ended December 31, 2008 due principally to the expansion of our gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas, including the construction of a 60 MMCFD expansion of our Sweetwater processing plant and the construction of our Madill to Velma pipeline. The decrease in maintenance capital expenditures for the year ended December 31, 2008 when compared with the prior year was due to fluctuations in the timing of our scheduled maintenance activity.

Partnership Distributions

Subject to the restrictions noted below, our partnership agreement requires that we distribute 100% of available cash to our common unitholders and our General Partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

Our General Partner is granted discretion by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When our General Partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 2% of the aggregate amount of cash being distributed. During July 2007, our General Partner, holder of all of our incentive distribution rights, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. The General Partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the General Partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter. No incentive distributions were declared for the year ended December 31, 2009.

On May 29, 2009, we entered into an amendment to our senior secured credit facility (see Term Loan and Revolving Credit Facility) which, among other changes, required that we pay no cash distributions through the end of 2009. Commencing with the quarter ending March 31, 2010, cash distributions can be paid, only if our senior secured leverage ratio meets certain thresholds and we have minimum liquidity (both as defined in the credit agreement) of at least $50.0 million at the end of the quarter.

Off Balance Sheet Arrangements

As of December 31, 2009, our off balance sheet arrangements are limited to our letters of credit, issued under the provisions of our revolving credit facility, totaling $10.1 million. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety and (iii) counterparty support.

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Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments at December 31, 2009 (in thousands):

		Payments Due By Period			
Contractual cash obligations:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Total debt	$ 1,258,034	$	$	$ 759,505	$ 498,529
Interest on total debt(1)	553,294	93,281	186,562	142,606	130,845
Derivative-based obligations	43,314	32,549	10,414	351	
Operating leases	13,549	4,547	7,490	1,512	
Total contractual cash obligations	$ 1,868,191	$ 130,377	$ 204,466	$ 903,974	$ 629,374

(1) Based on the interest rates of our respective debt components as of December 31, 2009.

		Amount of Commitment Expiration Per Period			
Other commercial commitments:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Standby letters of credit	$ 10,080	$ 10,080	$	$	$
Total commercial commitments	$ 10,080	$ 10,080	$	$	$

Common Equity Offerings

In August 2009, we sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. We also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2.0% general partner interest in us. In addition, we issued warrants granting investors in our private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and revolving credit facility (see Term Loan and Revolving Credit Facility), and we made similar repayments with net proceeds from exercises of the warrants in January 2010 (see Subsequent Events).

The common units and warrants sold by us in the August 2009 private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement required us to (a) file a registration statement with the Securities and Exchange Commission for the privately placed common units and those underlying the warrants by September 21, 2009 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by November 18, 2009. We filed a registration statement with the Securities and Exchange Commission in satisfaction of the registration requirements of the registration rights agreement on September 3, 2009, and the registration statement was declared effective on October 14, 2009.

In June 2008, we sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, we sold 1,112,000 common units to

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Atlas Energy and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. We also received a capital contribution from the General Partner of $5.4 million for the General Partner to maintain its 2.0% general partner interest in us. We utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements.

In July 2007, we sold 25,568,175 common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125 billion. Of the 25,568,175 common units sold, 3,835,227 common units were purchased by AHD for $168.8 million. We also received a capital contribution from the General Partner of $23.1 million in order for the General Partner to maintain its 2.0% general partner interest in us. We utilized the net proceeds from the sale to partially fund the Chaney Dell and Midkiff/Benedum acquisitions (see Significant Acquisitions). The common units issued were subsequently registered with the Securities and Exchange Commission in November 2007.

Preferred Units

Class A Preferred Units

In April 2007, we and Sunlight Capital agreed to amend the terms of the then-outstanding 40,000 cumulative convertible preferred units (Class A Preferred Units) effective as of that date. The terms of the Class A Preferred Units were amended to entitle them to receive dividends of 6.5% per annum commencing in March 2008 and to be convertible, at Sunlight Capital s option, into common units commencing May 8, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of our common units as of the date of the notice of conversion. We could elect to pay cash rather than issue common units in satisfaction of a conversion request. We had the right to call the Class A Preferred Units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.22. If not converted into common units or redeemed prior to the second anniversary of the conversion commencement date, the Class A Preferred Units would automatically be converted into our common units in accordance with the agreement. In consideration of Sunlight Capital s consent to the amendment of the Class A Preferred Units, we issued $8.5 million of our 8.125% senior unsecured notes due 2015 to Sunlight Capital. We recorded the senior unsecured notes issued as long-term debt and a preferred unit dividend within Partners Capital on our consolidated balance sheet and, during the year ended December 31, 2007, reduced net income (loss) attributable to common limited partners and the General Partner by $3.8 million of this amount, which was the portion deemed to be attributable to the concessions of the common limited partners and the General Partner to the Class A preferred unitholder, on our consolidated statements of operations.

In December 2008, we redeemed 10,000 of the Class A Preferred Units for $10.0 million in cash under the terms of the agreement. The redemption was classified as a reduction of Class A Preferred Equity within Partners Capital on our consolidated balance sheet. Our 30,000 outstanding Class A preferred limited partner units were convertible into approximately 5,263,158 common limited partner units at December 31, 2008, which was based upon the market value of our common units and subject to provisions and limitations within the agreement between the parties, with an estimated fair value of approximately $31.6 million based upon the market value of our common units as of that date.

In January 2009, we and Sunlight Capital agreed to amend certain terms of the preferred units certificate of designation for the then-outstanding 30,000 Class A Preferred Units. The amendment (a) increased the dividend yield from 6.5% to 12.0% per annum, effective January 1, 2009, (b) established a new conversion commencement date on the outstanding Class A Preferred Units of April 1, 2009, (c) established Sunlight Capital s new conversion option price of $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of our common units, and (d) established a new price for our call redemption right of $27.25.

The amendment to the preferred units certificate of designation also required that we issue Sunlight Capital $15.0 million of our 8.125% senior unsecured notes due 2015 (see Senior Notes) to redeem 10,000 Class A Preferred Units. Our management estimated that the fair value of the $15.0 million 8.125% senior unsecured notes issued to redeem the Class A Preferred Units was approximately $10.0 million at the date of redemption based upon the market price of the publicly-traded senior notes. As such, we recorded the redemption by recognizing a $10.0 million reduction of Class A Preferred equity within Partners Capital, $15.0 million of additional long-term debt for the face value of the senior unsecured notes issued, and a $5.0 million discount on the issuance of the senior unsecured notes that is presented as a reduction of long-term debt on our consolidated balance sheet. The discount recognized upon issuance of the senior unsecured notes will be amortized to interest expense in our consolidated statements of operations over the term of the notes based upon the effective interest rate method.

The amendment to the preferred units certificate of designation also required that (a) we redeem 10,000 of the Class A Preferred Units for cash at the liquidation value on April 1, 2009 and (b) that if Sunlight Capital made a conversion request of the remaining 10,000 Class A Preferred Units between April 1, 2009 and June 1, 2009, we had the option of redeeming the Class A Preferred Units for cash at the stipulated liquidation value or converting the Class A Preferred Units into our common limited partner units at the stipulated conversion price. If Sunlight Capital made a conversion request subsequent to June 1, 2009, 5,000 of the 10,000 Class A Preferred Units would have been required to be redeemed in cash, while we had the option of redeeming the remaining 5,000 Class A Preferred Units in cash or converting the preferred units into our common limited partner units.

On April 1, 2009, we redeemed 10,000 of the Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $10.0 million, in accordance with the terms of the amended preferred units certificate of designation. On April 13, 2009, we converted 5,000 of the Class A Preferred Units into 1,465,653 common units in accordance with the terms of the amended preferred units certificate of designation. We reclassified $5.0 million from Class A preferred limited partner equity to common limited partner equity within Partners Capital when these preferred units were converted into common limited partner units. On May 5, 2009, we redeemed the remaining 5,000 Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $5.0 million, pursuant to the terms of the amended preferred units certificate of designation. Additionally, on May 5, 2009, we paid Sunlight Capital a preferred dividend of $0.2 million, representing the quarterly dividend on the 5,000 Class A Preferred units held by Sunlight Capital prior to our redemption.

Class B Preferred Units

In December 2008, we sold 10,000 12.0% cumulative convertible Class B preferred units of limited partner interests (the Class B Preferred Units) to AHD for cash consideration of $1,000 per Class B Preferred Unit (the Face Value) pursuant to a certificate of designation (the Class B Preferred Units Certificate of Designation). On March 30, 2009, AHD, pursuant to its right within the Class B Preferred Unit Purchase Agreement, purchased an additional 5,000 Class B Preferred Units at Face Value. We used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for our common units. The record date of determination for holders entitled to receive distributions of the Class B Preferred Units will be the same as the record date of determination for common unit holders entitled to receive quarterly distributions. Additionally, on March 30, 2009, we and AHD agreed to amend the terms of the Class B Preferred Units Certificate of Designation to remove the conversion feature, thus the Class B Preferred Units are not convertible into our common units. The amended Class B Preferred Units Certificate of Designation also gives us the right at any time to redeem some or all of the outstanding Class B Preferred Units for cash at an amount equal to the Class B Preferred Unit Liquidation Value being redeemed, provided that such redemption must be exercised for no less than the lesser of a) 2,500 Class B Preferred Units or b) the number of remaining outstanding Class B Preferred Units.

The cumulative sale of the Class B Preferred Units to AHD is exempt from the registration requirements of the Securities Act of 1933. Dividends paid on the Class B Preferred Units and the premium paid upon the redemption of the Class B Preferred Units, if any, will be recognized as a reduction of our net income (loss) in determining net income (loss) attributable to common unitholders and the General Partner. The Class B Preferred Units are reflected on our consolidated balance sheet as Class B preferred equity within Partners Capital.

Term Loan and Revolving Credit Facility

At December 31, 2009, we had a senior secured credit facility with a syndicate of banks which consisted of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at our option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rates on the outstanding revolving credit facility and term loan borrowings at December 31, 2009 were 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $10.1 million was outstanding at December 31, 2009. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet.

In June 2008, we entered into an amendment to our credit facility agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to our early termination of certain derivative contracts (see Item 8: Financial Statements and Supplementary Data Note 12) in calculating our Consolidated EBITDA. Pursuant to this amendment, in June 2008 we repaid $122.8 million of our outstanding term loan and repaid $120.0 million of outstanding borrowings under the revolving credit facility with proceeds from our issuance of $250.0 million of 10-year, 8.75% senior unsecured notes (see Senior Notes). Additionally, pursuant to this amendment, in June 2008 our lenders increased their commitments for our revolving credit facility by $80.0 million to $380.0 million.

On May 29, 2009, we entered into an amendment to our credit facility agreement which, among other changes:

- increased the applicable margin above adjusted LIBOR to either (i) the federal funds rate plus 0.5% or (ii) the Wachovia Bank prime rate upon which borrowings under the credit facility bear interest;

- for borrowings under the credit facility that bear interest at LIBOR plus the applicable margin, set a floor for the adjusted LIBOR interest rate of 2.0% per annum;

- increased the maximum ratio of total funded debt (as defined in the credit agreement) to consolidated EBITDA (as defined in the credit agreement; the leverage ratio) and decreased the minimum ratio of interest coverage (as defined in the credit agreement) that the credit facility requires us to maintain;

- instituted a maximum ratio of senior secured funded debt (as defined in the credit agreement) to consolidated EBITDA (the senior secured leverage ratio) that the credit facility requires us to maintain;

- required that we pay no cash distributions during the remainder of the year ended December 31, 2009 and allows us to pay cash distributions commencing with the quarter ending March 31, 2010, only if our senior secured leverage ratio is less than 2.75x and we have minimum liquidity (as defined in the credit agreement) of at least $50.0 million;

- generally limited our annual capital expenditures to $95.0 million for the remainder of fiscal 2009 and $70.0 million each year thereafter, unless certain covenants are achieved;

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generally limits our annual capital contributions to Laurel Mountain to $10.0 million provided that if less than $10.0 million is paid in any given year that the shortfall may be carried over to the following year;

permitted us to retain (i) up to $135.0 million of net cash proceeds from dispositions completed in fiscal 2009 for reinvestment in similar replacement assets within 360 days, and (ii) up to $50.0 million of net cash proceeds from dispositions completed in any subsequent fiscal year subject to certain limitations as defined within the credit agreement; and

instituted a mandatory repayment requirement of the outstanding senior secured term loan from excess cash flow (as defined in the credit agreement) based upon our leverage ratio.

Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum joint ventures and the Laurel Mountain joint venture. Borrowings are also secured by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are also unable to borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement. We are in compliance with these covenants as of December 31, 2009.

The events which constitute an event of default for our credit facility include payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. The credit facility requires us to maintain the following ratios:

Fiscal quarter ending:	Maximum Leverage Ratio	Maximum Senior Secured Leverage Ratio	Minimum Interest Coverage Ratio
December 31, 2009	8.50x	5.25x	1.70x
March 31, 2010	9.25x	5.75x	1.40x
June 30, 2010	8.00x	5.00x	1.65x
September 30, 2010	7.00x	4.25x	1.90x
December 31, 2010	6.00x	3.75x	2.20x
Thereafter	5.00x	3.00x	2.75x

As of December 31, 2009, our leverage ratio was 5.2 to 1.0, our senior secured leverage ratio was 3.2 to 1.0, and our interest coverage ratio was 2.5 to 1.0.

Senior Notes

At December 31, 2009, we had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with a net $3.9 million of unamortized discount as of December 31, 2009. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, we may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under our credit facility.

In December 2008, we repurchased approximately $60.0 million in face amount of our Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million in face amount of our 8.125% Senior Notes and approximately $27.0 million in face amount of our 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue.

In January 2009, we issued Sunlight Capital $15.0 million of our 8.125% Senior Notes to redeem 10,000 Class A Preferred Units (see Preferred Units). Our management estimated that the fair value of the $15.0 million 8.125% Senior Notes issued was approximately $10.0 million at the date of issuance based upon the market price of the publicly-traded Senior Notes. As such, we recognized a $5.0 million discount on the issuance of the Senior Notes, which is presented as a reduction of long-term debt on our consolidated balance sheet. The discount recognized upon issuance of the Senior Notes will be amortized to interest expense in our consolidated statements of operations over the term of the 8.125% Senior Notes based upon the effective interest rate method.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We are in compliance with these covenants as of December 31, 2009.

In connection with the issuance of the 8.75% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If we did not meet the aforementioned deadline, the 8.75% Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that we had caused the exchange offer to be consummated. On November 21, 2008, we filed an exchange offer registration statement for the 8.75% Senior Notes with the Securities and Exchange Commission, which was declared effective on December 16, 2008. The exchange offer was consummated on January 21, 2009, thereby fulfilling all of the requirements of the 8.75% Senior Notes registration rights agreement by the specified dates.

Environmental Regulation

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

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Environmental laws and regulations have changed substantially and rapidly over the last 25 years, including recent legislation regarding climate change, and we anticipate that there will be continuing changes. One trend in environmental regulation is to increase reporting obligations and place more restrictions and limitations on activities, such as emissions of greenhouse gases and other pollutants, generation and disposal of wastes and use, storage and handling of chemical substances, that may impact human health, the environment and/or endangered species. Related to greenhouse gas emissions, cap and trade programs and/or carbon tax programs are being considered by Congress. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we process. Depending on the design and implementation of carbon tax programs, our operations could face additional taxes and higher costs of doing business. Although we would not be impacted to a greater degree than other similarly situated gatherers and processors of natural gas or NGLs, a stringent greenhouse gas control program could result in a significant effect on our cost of doing business. However, it is difficult to assess the timing and effect of the pending legislation.

We have developed and implemented a greenhouse gas monitoring plan (the Plan) in response to the EPA s promulgation of the Mandatory Greenhouse Gas Reporting Rule in 40 CFR 98. The Plan is designed to ensure that we achieve and maintain compliance with those facets of the rule which affect our operating facilities. We are diligently and continuously working to ensure that the necessary resources from both within and outside the organization are engaged to provide the information and services required to execute the Plan.

We continue to monitor regulatory and legislative activities regarding greenhouse gas production, detection, reporting and mitigation issues. We recognize that greenhouse gas issues continue to be very dynamic topics of discussion within the scientific, business and political communities, and we are committed to staying abreast of developing rules and mandates that will affect our operations and business activities. We participate within industry organizations in order that we may actively contribute to consolidated initiatives that are continuously monitoring, addressing and contributing to these greenhouse gas issues both during and following their development.

Other increasingly strict environmental restrictions and limitations have resulted in increased operating costs for us and other similar businesses throughout the United States. It is possible that the costs of compliance with environmental laws and regulations may continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly, but there can be no assurance that we will identify and properly anticipate each such charge, or that our efforts will prevent material costs, if any, from rising.

Inflation and Changes in Prices

Inflation affects the operating expenses of our operations due to the increase in costs of labor and supplies. While inflation did not have a material impact on our results of operations for the years ended December 31, 2009, 2008 and 2007, the energy sector realized increased costs during 2008, caused by the demand in energy equipment and services due to the increase in commodity prices. Commodity prices have decreased from their highs in 2008 and the related costs have also declined. While we anticipate that inflation will affect our future operating costs, we cannot predict the timing or amounts of any such effects.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of

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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 depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. We summarize our significant accounting policies within our consolidated financial statements included in Item 8, Financial Statements and Supplementary Data. The critical accounting policies and estimates we have identified are discussed below.

Depreciation and Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets. The cost of properties, plants 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 elsewhere in this document.

As discussed below, we recognized an impairment of goodwill at December 31, 2008. We believe this impairment of goodwill was an event that warranted assessment of our long-lived assets for possible impairment. During the year ended December 31, 2009, we completed an evaluation of certain assets based on the current operating conditions and business plans for those assets, including idle and inactive pipelines and equipment. Based on the results of this review, we recognized an impairment charge of approximately $10.3 million for the year ended December 31, 2009, within goodwill and other asset impairments on our consolidated statements of operations.

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. Under the prevailing accounting literature, an impairment loss should be recognized if the carrying value of an entity s reporting units exceeds its estimated fair value. Because quoted market prices for our 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 assets. A key component of these fair value determinations is a reconciliation of the sum of these net present value calculations to market capitalization. Prevailing accounting literature acknowledge that the observed market prices of individual trades of an entity s equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity s individual equity securities. In most industries, including ours, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above net present value calculations have been determined, we also add a control premium to the calculations. This control premium is subject to judgment and

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is based on observed acquisitions in our industry. The resultant fair values calculated for the reporting units are then compared to observable metrics on large mergers and acquisitions in our industry to determine whether those valuations appear reasonable in management s judgment.

As a result of our impairment evaluation at December 31, 2008, we recognized a $676.9 million non-cash impairment charge within our consolidated statements of operations for the year ended December 31, 2008. The goodwill impairment resulted from the reduction in our estimated fair value of reporting units in comparison to their carrying amounts at December 31, 2008. Our estimated fair value of the reporting units was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. These estimates were subjective and based upon numerous assumptions about future operations and market conditions, which are subject to change. There were no goodwill impairments recognized by us during the years ended December 31, 2009 and 2007. See Goodwill in Item 8: Financial Statements and Supplementary Data Note 2 for information regarding our impairment of goodwill and other assets.

Fair Value of Financial Instruments

FASB ASC established a hierarchy to measure 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 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.

We use a fair value methodology to value the assets and liabilities for our respective outstanding derivative contracts (see Item 8: Financial Statements and Supplementary Data Note 13). At December 31, 2009, all of our derivative contracts are defined as Level 2, with the exception of our NGL fixed price swaps and NGL options. Our Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. Our interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for our NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations and therefore are defined as Level 3. Valuations for our NGL options are based on forward price curves developed by the related financial institutions, and therefore are defined as Level 3.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in interest rates and oil and natural gas 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 our market risk sensitive instruments were entered into for purposes other than trading.

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodical use of derivative instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2009. Only the potential impact of hypothetical assumptions is 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 to our commodity and interest-rate derivative contracts are banking institutions currently participating in our revolving credit facility. We may choose to do business with counterparties outside of our credit facility in the future. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At December 31, 2009, we had a $380.0 million senior secured revolving credit facility ($326.0 million outstanding). We also had $433.5 million outstanding under our senior secured term loan at December 31, 2009. Borrowings under the credit facility bear interest, at our option at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). On May 29, 2009, we entered into an amendment to our senior secured revolving credit facility agreement which, among other changes, set a floor for the LIBOR interest rate of 2.0% per annum. The weighted average interest rate for the revolving credit facility borrowings was 6.8% at December 31, 2009, and the weighted average interest rate for the term loan borrowings was 6.8% at December 31, 2009.

At December 31, 2009, we have interest rate derivative contracts having aggregate notional principal amounts of $450.0 million. Under the terms of these agreements, we will pay weighted average interest rates of 3.0%, plus the applicable margin as defined under the terms of our revolving credit facility, and will receive LIBOR, plus the applicable margin, on the notional principal amounts. The interest rate swap agreements are in effect as of December 31, 2009 and expire during periods ranging from January 30, 2010 through April 30, 2010. Beginning May 29, 2009, we discontinued hedge accounting for our interest rate derivatives which were qualified as hedges under prevailing accounting literature. As such, subsequent changes in fair value of these derivatives will be recognized immediately within other income (loss), net in our consolidated statements of operations.

Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by $0.7 million.

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Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. Average estimated unhedged 2010 market prices for NGLs, natural gas and condensate, based upon New York Mercantile Exchange (NYMEX) forward price curves as of February 15, 2010, are $1.10 per gallon, $5.71 per MMBTU and $76.26 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended December 31, 2010 by approximately $27.2 million.

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price and interest rate risk management activities. We enter into financial swap and option instruments to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. We also enter into financial swap instruments to hedge certain portions of our floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. Under 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. 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.

On July 1, 2008, we discontinued hedge accounting for our existing commodity derivatives which were qualified as hedges for accounting purposes. In addition, beginning May 29, 2009, we discontinued hedge accounting for our existing interest rate derivatives which were qualified as hedges under prevailing accounting literature. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), net in our consolidated statements of operations. The fair value of these commodity derivative instruments at June 30, 2008 and interest rate derivative instruments at May 29, 2009, which were recognized in accumulated other comprehensive loss (OCI) within Partners Capital on our consolidated balance sheet, will be reclassified to our consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings.

During the years ended December 31, 2009 and 2008, we made net payments of $5.0 million and $274.0 million, respectively, related to the early termination of derivative contracts. The majority of these derivative contracts were put into place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. Additional terminated derivative contracts extend through the fourth quarter of 2012. During the years ended December 31, 2009, 2008 and 2007, we recognized the following derivative activity related to the early termination of these derivative instruments within our consolidated statements of operations (in thousands):

Early termination of derivative contracts

	For the Years Ended December 31,		
	2009	**2008**	**2007**
Cash paid for early termination	$ (5,000)	$ (273,987)	$
Less: Deferred recognition of loss on early termination[(1)]		(76,345)	
	(5,000)	(197,642)	
Net cash derivative expense included within natural gas and liquids revenue		2,322	
Net cash derivative expense included within other loss, net	(5,000)	(199,964)	
Recognition of deferred hedge loss from prior periods included within natural gas and liquids revenue	(68,479)	(32,389)	
Recognition of deferred hedge gain (loss) from prior periods included within other income (loss), net	44,861	(39,218)	
Total recognized loss from early termination	$ (28,618)	$ (269,249)	$

(1)

Deferred recognition based upon effective portion of hedges deferred to OCI, plus theoretical premium related to unwound options which had previously been purchased or sold as part of costless collars

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The following table summarizes our gross fair values of derivative instruments for the period indicated:

Interest Fixed-Rate Swaps

Term	Amount	Type		Fair Value[(1)] Asset/ (Liability) (in thousands)
January 2008-January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	$ (438)
April 2008-April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	(2,402)
Total Interest Rate Swaps				$ (2,840)

Fixed Price Swaps

Production Period	Purchased/ Sold	Commodity	Volumes[(2)]	Average Fixed Price	Fair Value[(1)] Asset/ (Liability) (in thousands)
2010	Purchased	Natural Gas	4,380,000	$ 8.635	$ (13,306)
2010	Sold	Natural Gas Basis	4,500,000	(0.638)	(1,936)
2010	Purchased	Natural Gas Basis	8,880,000	(0.597)	3,369
2011	Sold	Natural Gas Basis	1,920,000	(0.728)	(845)
2011	Purchased	Natural Gas Basis	1,920,000	(0.758)	903
2012	Sold	Natural Gas Basis	720,000	(0.685)	(269)
2012	Purchased	Natural Gas Basis	720,000	(0.685)	269
Total Fixed Price Swaps					$ (11,815)

NGL Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes[(2)]	Average Strike Price	Fair Value[(1)] Asset/ (Liability) (in thousands)
2010	Purchased	Put	Propane	35,910,000	$ 1.022	$ 1,137
2010	Purchased	Put	Normal Butane	3,654,000	1.205	29
2010	Purchased	Put	Natural Gasoline	3,906,000	1.545	102
Total NGL Options						$ 1,268

Crude Oil Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes[(2)]	Average Strike Price	Fair Value[(1)] Asset/ (Liability) (in thousands)
2010	Purchased	Put	Crude Oil	897,000	73.12	3,518
2010	Sold	Call	Crude Oil	3,361,500	81.23	(23,183)
2010	Purchased[(3)]	Call	Crude Oil	714,000	120.00	430

2011	Sold	Call	Crude Oil	678,000	94.68		(6,687)
2011	Purchased[3]	Call	Crude Oil	252,000	120.00		1,017
2012	Sold	Call	Crude Oil	498,000	95.83		(6,197)
2012	Purchased[3]	Call	Crude Oil	180,000	120.00		1,175
Total Crude Options						$	(29,927)
Total Fair Value						$	(43,314)

(1) See Item 7: Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Fair Value of Financial Instruments for discussion on fair value methodology.

(2) Volumes for Natural Gas are stated in MMBTU s. Volumes for NGLs are stated in gallons. Volumes for Crude are stated in barrels.

(3) Calls purchased for 2010 through 2012 represent offsetting positions for calls sold. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited the accompanying consolidated balance sheets of Atlas Pipeline Partners, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), partners capital, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Partnership retrospectively adopted new accounting pronouncements related to the accounting for noncontrolling interests in the consolidated financial statements and the calculation of earnings per unit.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atlas Pipeline Partners, L.P. s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 5, 2010 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

March 5, 2010

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,021	$ 1,445
Accounts receivable affiliates		537
Accounts receivable	100,721	100,000
Current portion of derivative asset	998	44,961
Prepaid expenses and other	15,404	10,996
Current assets of discontinued operations		13,441
Total current assets	118,144	171,380
Property, plant and equipment, net	1,684,384	1,781,011
Intangible assets, net	168,091	193,647
Investment in joint venture	132,990	
Long-term portion of derivative asset	361	
Other assets, net	33,993	24,993
Long-term assets of discontinued operations		242,165
	$ 2,137,963	$ 2,413,196
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable affiliates	$ 2,043	$
Accounts payable	22,928	66,571
Accrued liabilities	14,348	13,386
Accrued interest payable	9,652	2,423
Current portion of derivative liability	33,547	60,396
Accrued producer liabilities	66,211	66,846
Current liabilities of discontinued operations		10,572
Total current liabilities	148,729	220,194
Long-term portion of derivative liability	11,126	48,159
Long-term debt	1,254,183	1,493,427
Other long-term liability	398	574
Commitments and contingencies		
Partners Capital:		
Class A preferred limited partner s interest		27,853
Class B preferred limited partner s interest	14,955	10,007
Common limited partners interests	787,834	735,742
Investment in Class B cumulative preferred member units of Atlas Pipeline Holdings II, LLC (reported as treasury units)	(15,000)	
General Partner s interest	15,853	14,521
Accumulated other comprehensive loss	(49,190)	(104,944)

	754,452	683,179
Non-controlling interest	(30,925)	(32,337)
Total Partners Capital	723,527	650,842
	$ 2,137,963	$ 2,413,196

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31,		
	2009	**2008**	**2007**
Revenue:			
Natural gas and liquids	$ 778,544	$ 1,342,782	$ 739,851
Transportation, compression and other fees affiliates	17,536	43,293	33,169
Transportation, compression and other fees third parties	15,433	21,196	13,322
Equity income in joint venture	4,043		
Gain on asset sale	111,440		
Other loss, net	(22,791)	(55,504)	(174,129)
Total revenue and other loss, net	904,205	1,351,767	612,213
Costs and expenses:			
Natural gas and liquids	594,742	1,080,940	576,415
Plant operating	58,474	60,835	34,667
Transportation and compression	6,657	11,249	6,235
General and administrative	34,994	(3,325)	53,661
Compensation reimbursement affiliates	2,731	1,487	5,939
Depreciation and amortization	92,434	82,841	43,903
Goodwill and other asset impairment loss	10,325	676,860	
Interest	103,629	85,991	62,592
Gain on early extinguishment of debt		(19,867)	
Total costs and expenses	903,986	1,977,011	783,412
Income (loss) from continuing operations	219	(625,244)	(171,199)
Discontinued operations:			
Gain on sale of discontinued operations	51,078		
Earnings of discontinued operations	11,417	20,546	30,830
Income from discontinued operations	62,495	20,546	30,830
Net income (loss)	62,714	(604,698)	(140,369)
(Income) loss attributable to non-controlling interests of continuing operations	(3,176)	22,781	(3,940)
Preferred unit dividend effect			(3,756)
Preferred unit dividends	(900)	(1,769)	
Preferred unit imputed dividend cost		(505)	(2,494)
Net income (loss) attributable to common limited partners and the General Partner	$ 58,638	$ (584,191)	$ (150,559)

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Allocation of net income (loss) attributable to common limited partners and the General Partner:			
Common limited partners interest:			
Continuing operations	$ (3,779)	$ (615,583)	$ (193,282)
Discontinued operations	61,239	20,133	30,211
	57,460	(595,450)	(163,071)
General Partner s interest:			
Continuing operations	(78)	10,846	11,893
Discontinued operations	1,256	413	619
	1,178	11,259	12,512
Net income (loss) attributable to common limited partners and the General Partner:			
Continuing operations	(3,857)	(604,737)	(181,389)
Discontinued operations	62,495	20,546	30,830
	$ 58,638	$ (584,191)	$ (150,559)
Net income (loss) attributable to common limited partners per unit:			
Basic:			
Continuing operations	$ (0.08)	$ (14.43)	$ (7.94)
Discontinued operations	1.27	0.47	1.25
	$ 1.19	$ (13.96)	$ (6.69)
Diluted:			
Continuing operations	$ (0.08)	$ (14.43)	$ (7.94)
Discontinued operations	1.27	0.47	1.25
	$ 1.19	$ (13.96)	$ (6.69)
Weighted average common limited partner units outstanding:			
Basic	48,299	42,513	24,171
Diluted	48,299	42,513	24,171

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended December 31,		
	2009	2008	2007
Net income (loss)	$ 62,714	$ (604,698)	$ (140,369)
(Income) loss attributable to non-controlling interests	(3,176)	22,781	(3,940)
Preferred unit dividend effect			(3,756)
Preferred unit dividends	(900)	(1,769)	
Preferred unit imputed dividend cost		(505)	(2,494)
Net income (loss) attributable to common limited partners and the General Partner	58,638	(584,191)	(150,559)
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as hedges	(2,268)	(97,435)	(101,968)
Reclassification adjustment to earnings for de-designation of cash flow hedges			12,611
Add: adjustment for realized losses reclassified to net income (loss)	58,022	54,541	49,393
Total other comprehensive income (loss)	55,754	(42,894)	(39,964)
Comprehensive income (loss)	$ 114,392	$ (627,085)	$ (190,523)

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands, except unit data)

	Number of Limited Partner Units			Class A Preferred	Class B Preferred	Common		Accumulated Other Comprehensive	Class B Preferred Units of Atlas Pipeline		Total
	Class A Preferred	Class B Preferred	Common	Limited Partner	Limited Partner	Limited Partner	General Partner	Income (Loss)	Holdings II, LLC	Non-Controlling Interests	Partners Capital
Balance at January 1, 2007	40,000		13,080,418	$ 39,381	$	$ 350,805	$ 11,034	$ (22,086)	$	$	$ 379,134
Issuance of common units			25,568,175			1,115,149					1,115,149
General Partner capital contribution							23,076				23,076
Class A preferred unit dividend and costs				(8,555)							(8,555)
Unissued common units under incentive plans						36,346					36,346
Issuance of units under incentive plans			109,988			(40)					(40)
Distribution paid						(69,668)	(17,209)			(6,103)	(92,980)
Other comprehensive loss								(39,964)			(39,964)
Net income (loss)				6,250		(163,071)	12,512			3,940	(140,369)
Balance at December 31, 2007	40,000		38,758,581	37,076		1,269,521	29,413	(62,050)		(2,163)	1,271,797
Issuance of common units			7,140,000			256,928					256,928
Redemption of Class A cumulative convertible preferred limited partner units	(10,000)			(10,053)							(10,053)
Issuance of Class B cumulative convertible preferred limited partner units		10,000			10,000						10,000
General Partner capital contribution							5,452				5,452
Class A preferred unit dividends				(1,437)							(1,437)
Unissued common units under incentive plans						(34,010)					(34,010)
Issuance of units under incentive plans			56,227								
Distribution paid						(161,248)	(31,602)			(7,393)	(200,243)
Other comprehensive loss								(42,894)			(42,894)

Net income (loss)				2,267	7	(595,449)	11,258			(22,781)	(604,698)
Balance at December 31, 2008	30,000	10,000	45,954,808	27,853	10,007	735,742	14,521	(104,944)		(32,337)	650,842
Issuance of common units			2,689,765			16,074					16,074
Redemption/Conversion of Class A cumulative convertible preferred limited partner units	(30,000)		1,465,653	(27,528)		2,528					(25,000)
Issuance of Class B preferred limited partner units		5,000			4,955						4,955
General Partner capital contribution							658				658
Distributions paid				(775)	(457)	(24,671)	(505)			(1,764)	(28,172)
Unissued common units under incentive plans						702					702
Issuance of common units under incentive plans			406,877								
Purchase of Class B cumulative preferred member units of Atlas Pipeline Holdings II, LLC (reported as treasury units)									(15,000)		(15,000)
Other comprehensive income								55,754			55,754
Net income				450	450	57,459	1,179			3,176	62,714
Balance at December 31, 2009		15,000	50,517,103	$	$ 14,955	$ 787,834	$ 15,853	$ (49,190)	$ (15,000)	$ (30,925)	$ 723,527

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 62,714	$ (604,698)	$ (140,369)
Less: Income from discontinued operations	62,495	20,546	30,830
Net income (loss) from continuing operations	219	(625,244)	(171,199)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation and amortization	92,434	82,841	43,903
Goodwill and other asset impairment loss	10,325	676,860	
Gain on early extinguishment of debt		(19,867)	
Equity income in joint venture	(4,043)		
Distributions received from joint venture	4,310		
Loss (gain) on asset sales and dispositions	(111,440)		805
Non-cash loss (gain) on derivative value, net	35,474	(208,813)	169,424
Non-cash compensation expense (income)	702	(34,010)	36,306
Amortization of deferred finance costs	8,016	5,946	7,380
Other		(7,393)	(6,103)
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable and prepaid expenses and other	(5,203)	42,162	(96,090)
Accounts payable and accrued liabilities	5,544	(19,945)	72,837
Accounts payable and accounts receivable affiliates	2,580	2,700	4,267
Net cash provided by (used in) continuing operating activities	38,918	(104,763)	61,530
Net cash provided by discontinued operating activities	16,935	45,569	38,914
Net cash provided by (used in) operating activities	55,853	(59,194)	100,444
CASH FLOWS FROM INVESTING ACTIVITIES:			
Net cash received (paid) for acquisitions		31,429	(1,884,458)
Capital contribution to joint venture	(1,680)		
Capital expenditures	(154,916)	(300,723)	(120,833)
Net proceeds from sales of assets	112,035		553
Other	(4,910)	1,561	(1,026)
Net cash used in continuing investing activities	(49,471)	(267,733)	(2,005,764)
Net cash provided by (used in) discontinued investing activities	290,594	(25,211)	(18,879)
Net cash provided by (used in) investing activities	241,123	(292,944)	(2,024,643)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from issuance of debt		244,854	817,131
Repayment of debt	(273,675)	(162,938)	
Borrowings under credit facility	694,000	787,400	320,500
Repayments under credit facility	(670,000)	(590,400)	(253,500)
Net proceeds from issuance of units	16,074	256,928	1,115,149
Net proceeds from issuance of Class B preferred limited partner units	4,955	10,000	
Purchase of Class B cumulative preferred units of Atlas Pipeline Holdings II, LLC	(15,000)		

Redemption of Class A preferred limited partner units	(15,000)	(10,053)	
General Partner capital contributions	658	5,452	23,076
Net distributions paid to non-controlling interests	(1,764)		
Distributions paid to common limited partners, the General Partner and preferred limited partner	(26,349)	(193,741)	(86,293)
Other	(11,299)	(6,260)	(1,004)
Net cash provided by (used in) financing activities	(297,400)	341,242	1,935,059
Net change in cash and cash equivalents	(424)	(10,896)	10,860
Cash and cash equivalents, beginning of year	1,445	12,341	1,481
Cash and cash equivalents, end of year	$ 1,021	$ 1,445	$ 12,341

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 NATURE OF OPERATIONS

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering and processing of natural gas. The Partnership s operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 2% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 5,754,253 common limited partner units in the Partnership (see Note 5) and 15,000 $1,000 par value Class B preferred limited partner units (see Note 6). At December 31, 2009, the Partnership had 50,517,103 common limited partnership units outstanding, including the 5,754,253 common units held by the General Partner, plus the 15,000 $1,000 par value Class B preferred units held by the General Partner.

The Partnership s General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas Energy, Inc. and its affiliates (Atlas Energy), a publicly-traded company (NASDAQ: ATLS) which at December 31, 2009, owned a 64.3% ownership interest in AHD s common units and 1,112,000 of the Partnership s common limited partnership units, representing a 2.2% ownership interest in the Partnership. On September 29, 2009, Atlas America, Inc., the former name of Atlas Energy, and Atlas Energy Resources, LLC (Atlas Energy Resources), a former publicly-traded Delaware limited liability company, consummated a merger pursuant to a definitive merger agreement, whereby Atlas Energy s wholly owned subsidiary merged with Atlas Energy Resources (the Merger), with Atlas Energy Resources surviving as Atlas America s wholly-owned subsidiary. Additionally, Atlas America changed its name to Atlas Energy, Inc. upon completion of the Merger.

The majority of the natural gas that the Partnership and its affiliates, including Laurel Mountain Midstream LLC (Laurel Mountain), gather in Appalachia is derived from wells operated by Atlas Energy Resources. Laurel Mountain, which was formed in May 2009, is a joint venture between the Partnership and The Williams Companies, Inc. (NYSE: WMB) (Williams) in which the Partnership retains 49% ownership interest and Williams retains the remaining 51% ownership interest (see Note 3).

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-K from the amounts previously presented to reflect the following items:

In May 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system (NOARK) (see Note 4). In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 205-20-45 Reporting Discontinued Operations, the Partnership has retrospectively adjusted its prior period consolidated financial statements to reflect the amounts related to the operations of NOARK as discounted operations;

The adoption of FASB ASC 810-10-65, Non-Controlling Interest in Consolidated Financial Statements, which clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. FASB also requires consolidated net income to be reported and disclosed

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

on the face of the consolidated statements of operations at amounts that include the amounts attributable to both the parent and the non-controlling interest. The Partnership adopted these requirements on January 1, 2009, and has reflected the retrospective application for all periods presented;

The adoption of FASB ASC 260-10-45, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities, which applies to the calculation of earnings per unit (EPU) described in previous guidance for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPU pursuant to the two-class method. The Partnership adopted these requirements on January 1, 2009 and has reflected the retroactive application for all periods presented; and

The adoption of FASB ASC 260-10-55, Application of the Two-Class Method, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. It also considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. The Partnership s management believes that the partnership agreement contractually limits cash distributions to available cash and, therefore, undistributed earnings are no longer allocated to the incentive distribution rights. The Partnership adopted these requirements on January 1, 2009 and has reflected the retroactive application for all periods presented.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Non-Controlling Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership s wholly-owned and majority-owned subsidiaries. The General Partner s interest in the Operating Partnership is reported as part of its overall 2% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

The Partnership s consolidated financial statements also include its 95% ownership interest in joint ventures which individually own a 100% ownership interest in the Chaney Dell natural gas gathering system and processing plants and a 72.8% undivided interest in the Midkiff/Benedum natural gas gathering system and processing plants. The Partnership consolidates 100% of these joint ventures and reflects the non-controlling 5% ownership interest in the joint ventures as non-controlling interests on its statements of operations. The Partnership also reflects the 5% ownership interest in the net assets of the joint ventures as non-controlling interests and as a component of Partners Capital on its consolidated balance sheets. The joint ventures have a $1.9 billion note receivable from the holder of the 5% ownership interest in the joint ventures, which is reflected within non-controlling interests on the Partnership s consolidated balance sheets.

The Midkiff/Benedum joint venture has a 72.8% undivided joint venture interest in the Midkiff/Benedum system, of which the remaining 27.2% interest is owned by Pioneer Natural Resources

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company (NYSE: PXD) (Pioneer). Accordingly, the Midkiff/Benedum joint venture proportionally consolidates its 72.8% ownership interest in the assets and liabilities and operating results of the Midkiff/Benedum system.

Equity Method Investments

The Partnership s consolidated financial statements include its 49% ownership interest in Laurel Mountain, a joint venture which owns and operates the Partnership s former Appalachia Basin natural gas gathering systems, excluding the Partnership s northeastern Tennessee operations. The Partnership accounts for its investment in the joint venture under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint venture s net income (loss) as equity income on its consolidated statements of operations (see Note 3).

Use of Estimates

The preparation of the Partnership s consolidated 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 Partnership s consolidated financial statements, as well as the reported amounts of revenue and expense during the reporting periods. The Partnership s consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depreciation and amortization, asset impairment, the fair value of derivative instruments, the probability of forecasted transactions, the allocation of purchase price to the fair value of assets acquired and other items. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

Cash Equivalents

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

Receivables

In evaluating the realizability of its accounts receivable, the Partnership performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by the Partnership s review of its customers credit information. The Partnership extends credit on an unsecured basis to many of its customers. At December 31, 2009 and 2008, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated 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. Maintenance and repairs are expensed as incurred. Major renewals and

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The Partnership follows the composite method of depreciation and has determined the composite groups to be the major asset classes of its gathering and processing systems. Under the composite depreciation method, any gain or loss upon disposition or retirement of pipeline, gas gathering and processing components, is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership s results of operations.

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or 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.

As discussed below, the Partnership recognized an impairment of goodwill at December 31, 2008. The Partnership believes this impairment of goodwill was an event that warranted assessment of its long-lived assets for possible impairment. During the year ended December 31, 2009, the Partnership completed an evaluation of certain assets based on the current operating conditions and business plans for those assets, including idle and inactive pipelines and equipment. Based on the results of this review, the Partnership recognized an impairment charge of approximately $10.3 million for the year ended December 31, 2009, within goodwill and other asset impairments on the Partnership s consolidated statements of operations.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 6.4%, 6.3% and 8.0% for the years ended December 31, 2009, 2008 and 2007, respectively. The amount of interest capitalized was $2.8 million, $7.7 million and $2.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates. The Partnership records each derivative instrument in the balance sheet as either an asset or liability measured at fair value. Changes in a derivative instrument s fair value are recognized currently in the consolidated statements of operations. On July 1, 2008, the Partnership discontinued hedge accounting for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. Prior to discontinuance of hedge accounting, the fair value of these commodity derivative instruments was recognized in accumulated other comprehensive loss within Partners Capital on the Partnership s consolidated balance sheet and reclassified to the Partnership s consolidated statements of operations at the time the originally hedged physical transactions affect earnings.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at December 31, 2009 and 2008 (in thousands):

	December 31, 2009	December 31, 2008	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,810	$ 12,810	8
Customer relationships	222,572	222,572	7 20
	$ 235,382	$ 235,382	
Accumulated Amortization:			
Customer contracts	$ (7,397)	$ (5,806)	
Customer relationships	(59,894)	(35,929)	
	$ (67,291)	$ (41,735)	
Net Carrying Amount:			
Customer contracts	$ 5,413	$ 7,004	
Customer relationships	162,678	186,643	
	$ 168,091	$ 193,647	

The Partnership amortizes intangible assets with finite useful lives over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence and expected renewals at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition, adjusted for management s estimate of whether these individual relationships will continue in excess or less than the average length. Amortization expense on intangible assets was $25.6 million, $25.6 million and $12.1 million for the years ended December 31, 2009, 2008 and 2007, respectively. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2010 to 2012 - $25.6 million; 2013 - $24.5 million; 2014 - $20.4 million.

Goodwill

The changes in the carrying amount of goodwill for the years ended December 31, 2009, 2008 and 2007 were as follows (in thousands):

	Years Ended December 31,		
	2009	2008(1)	2007(1)

Balance, beginning of year	$	$ 709,283	$ 63,441
Purchase price allocation adjustment Chaney Dell and Midkiff/Benedum acquisition			645,842
Post-closing purchase price adjustment with seller and purchase price allocation adjustment Chaney Dell and Midkiff/Benedum acquisition		(2,217)	
Recovery of state sales tax initially paid on transaction Chaney Dell and Midkiff/ Benedum acquisition		(30,206)	
Impairment loss		(676,860)	
Balance, end of year	$	$	$ 709,283

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4).

The Partnership tests its goodwill for impairment at each year end by comparing reporting unit estimated fair values to carrying values. Because quoted market prices for the Partnership s 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 assets. A key component of these fair value determinations is a reconciliation of the sum of these net present value calculations to the Partnership s market capitalization. The principles of prevailing accounting literature and its interpretations acknowledge that the observed market prices of individual trades of an entity s equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity s individual equity securities. In most industries, including the Partnership s, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above net present value calculations have been determined, the Partnership also adds a control premium to the calculations. This control premium is subject to judgment and is based on observed acquisitions in the Partnership s industry. The resultant fair values calculated for the reporting units are then compared to observable metrics on large mergers and acquisitions in the Partnership s industry to determine whether those valuations appear reasonable in management s judgment.

As a result of its impairment evaluation at December 31, 2008, the Partnership recognized a $676.9 million non-cash impairment charge within its consolidated statements of operations for the year ended December 31, 2008. The goodwill impairment resulted from the reduction in the Partnership s estimated fair value of reporting units in comparison to their carrying amounts at December 31, 2008. The Partnership s estimated fair value of its reporting units was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. There were no goodwill impairments recognized by the Partnership during the years ended December 31, 2009 and 2007.

The Partnership had adjusted its preliminary purchase price allocation for the acquisition of its Chaney Dell and Midkiff/Benedum systems since its July 2007 acquisition date by adjusting the estimated amounts allocated to goodwill, intangible assets and property, plant and equipment. Also, in April 2008, the Partnership received a $30.2 million cash reimbursement for sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems in July 2007. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement of the sales tax paid in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition (see Note 11).

Income Taxes

The Partnership is not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership s taxable income. Such taxable income may vary substantially from net income (loss) reported in the accompanying consolidated financial statements. Certain corporate subsidiaries of the Partnership are subject to federal and state income tax. The federal and state income taxes related to the Partnership and

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

these corporate subsidiaries were immaterial to the consolidated financial statements and are recorded in pre-tax income on a current basis only. Accordingly, no federal or state deferred income tax has been provided for in the accompanying consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership s tax returns and disallows the recognition of tax positions not deemed to meet a more-likely-than-not threshold of being sustained by the applicable tax authority. The Partnership s management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership s policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements as of December 31, 2009.

The Partnership files income tax returns in the U.S. federal and various state jurisdictions. The Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2006. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2009.

Stock-Based Compensation

All share-based payments to employees, including grants of employee stock options, are to be recognized in the financial statements based on their fair values. Compensation expense associated with share-based payments is recognized within general and administrative expenses on the Partnership s statement of operations from the date of the grant through the date of vesting amortized on a straight-line method. Generally, no expense is recorded for awards that do not vest due to forfeiture.

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners, which is determined after the deduction of net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner s and the preferred unitholder s interests, by the weighted average number of common limited partner units outstanding during the period. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2% interest and incentive distributions to be distributed for the quarter (see Note 8), with a priority allocation of net income to the General Partner s incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner s and limited partners ownership interests.

The Partnership presents net income (loss) per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management of the Partnership believes that the partnership agreement contractually limits cash distributions to available cash and, therefore, undistributed earnings are not allocated to the incentive distribution rights.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

EPU pursuant to the two-class method. The Partnership s phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plan and incentive compensation agreements (see Note 17), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award s vesting period. All prior period EPU computations have been retroactively adjusted to reflect the adoption of accounting standards summarized above related to EPU that were effective January 1, 2009.

The following is a reconciliation of net income (loss) from continuing operations and net income from discontinued operations allocated to the General Partner and common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands, except per unit data):

	Years Ended December 31,		
	2009	**2008[(1)]**	**2007[(1)]**
Continuing operations:			
Net income (loss)	$ 219	$ (625,244)	$ (171,199)
(Income) loss attributable to non-controlling interest	(3,176)	22,781	(3,940)
Preferred unit dividend effect			(3,756)
Preferred unit dividends	(900)	(1,769)	
Preferred unit imputed dividend cost		(505)	(2,494)
Net income (loss) attributable to common limited partners and the General Partner	(3,857)	(604,737)	(181,389)
General Partner s actual cash incentive distributions declared		23,472	15,857
General Partner s actual 2% ownership interest	(78)	(12,626)	(3,964)
Net income (loss) attributable to the general partner s ownership interests	(78)	10,846	11,893
Net loss attributable to common limited partners	(3,779)	(615,583)	(193,282)
Less: net loss attributable to participating securities phantom units		(2,109)	(1,302)
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$ (3,779)	$ (613,474)	$ (191,980)
Discontinued operations:			
Net income	$ 62,495	$ 20,546	$ 30,830
Net income attributable to the general partner s ownership interests (2% ownership interest)	1,256	413	619
Net income utilized in the calculation of net income from discontinued operations attributable to common limited partners per unit	$ 61,239	$ 20,133	$ 30,211

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4).

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, less income allocable to participating

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership s long-term incentive plan (see Note 17). The following table sets forth the reconciliation of the Partnership s weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Weighted average common limited partner units - basic	48,299	42,513	24,171
Add: effect of dilutive option incentive awards[(1)]			
Add: effect of dilutive unit warrants[(2)]			
Add effect of dilutive convertible preferred limited partner units[(3)]			
Weighted average common limited partner units - diluted	48,299	42,513	24,171

(1) For the year ended December 31, 2009, 100,000 unit options were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such unit options would have been anti-dilutive. There were no unit options or warrants outstanding for the years ended December 31, 2008 and 2007.

(2) For the year ended December 31, 2009, potential common limited partner units issuable upon exercise of the Partnership s warrants (see Note 6) were excluded from computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive. There were no warrants outstanding for the years ended December 31, 2008 and 2007.

(3) For the years ended December 31, 2008 and 2007, potential common limited partner units issuable upon conversion of the Partnership s Class A and Class B cumulative convertible preferred limited partner units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive. There were no convertible preferred limited partner units outstanding for the year ended December 31, 2009 (see Note 6 for additional information regarding the conversion features of the preferred limited partner units).

Environmental Matters

The Partnership is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Partnership has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures, including legislation related to greenhouse gas emissions. The Partnership accounts for environmental contingencies in accordance with prevailing accounting literature. 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. At this time, the Partnership is unable to assess the timing and/or effect of potential cap and trade programs or carbon taxes related to greenhouse gas emissions. The Partnership maintains insurance which may cover in whole or in part certain environmental expenditures. At December 31, 2009 and 2008, the Partnership had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

The Partnership has two reportable segments. The Mid-Continent segment consists of the Chaney Dell, Elk City/Sweetwater, Velma and Midkiff/Benedum operations, which are comprised of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

natural gas gathering and processing assets located in Oklahoma, Texas, and southern Kansas. The Appalachia segment is comprised of natural gas transportation, gathering and processing assets located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee. Effective May 31, 2009, the Appalachia operations were principally conducted through the Partnership s gathering system in Tennessee and its 49% ownership interest in Laurel Mountain, a joint venture to which the Partnership contributed its natural gas transportation, gathering and processing assets located in northeastern Appalachia. The Partnership recognizes its ownership interest in Laurel Mountain under the equity method of accounting. Mid-Continent revenues are primarily derived from the sale of Residue Gas and NGLs and gathering of natural gas. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates. These reportable segments reflect the way the Partnership manages its operations.

Revenue Recognition

The Partnership s revenue primarily consists of the fees earned from its gathering and processing operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced natural gas liquids (NGLs), if any, off of delivery points on its systems. Under other agreements, the Partnership gathers natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with the Partnership s gathering and processing operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas. Revenue is a function of the volume of natural gas that the Partnership gathers and processes and is not directly dependent on the value of the natural gas. The Partnership is also paid a separate compression fee on many of its systems. The fee is dependent upon the volume of gas flowing through its compressors and the quantity of compression stages utilized to gather the gas.

Percentage of Proceeds (POP) Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this contract-type, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership effectively owns a percentage of the commodity and revenues are directly correlated to its market value. POP Contracts may include a fee component which is charged to the producer.

Keep-Whole Contracts. These contracts require the Partnership, as the processor and gatherer, to gather or purchase raw natural gas at current market rates. The volume of gas gathered or purchased is based on the measured volume at an agreed upon location (generally at the wellhead). The volume of gas redelivered or sold at the tailgate of the Partnership s processing facility will be lower than the volume purchased at the wellhead primarily due to BTUs extracted when processed through a plant. Therefore, the Partnership bears the economic risk (the processing margin risk) that (i) the volume of Residue Gas available for redelivery to the producer may be less than received from the producer; or (ii) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that the Partnership paid for the unprocessed natural gas (plus, in either case, the cost of the natural gas the Partnership must purchase to return an equivalent volume, measured in BTU content, to producers to keep them whole with respect to their original measured volume). In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under Keep-Whole agreements is often lower in BTU content and thus, can meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods of margin risk.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership s records and management estimates of the related gathering and compression fees which are, in turn, based upon applicable product prices (see Use of Estimates accounting policy for further description). The Partnership had unbilled revenues at December 31, 2009 and 2008 of $65.4 million and $50.1 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income (loss), are referred to as other comprehensive income (loss) or OCI and for the Partnership only include changes in the fair value of unsettled derivative contracts which are accounted for as cash flow hedges (see Note 12).

Recently Adopted Accounting Standards

In June 2009, the FASB issued Accounting Standards Update 2009-01, Topic 105 Generally Acceptable Accounting Principles Amendments Based on Statement of Financial Accounting Standards No. 168 - The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (Update 2009-01). Update 2009-01 establishes the FASB Accounting Standards Codification (ASC) as the single source of authoritative U.S. generally accepted accounting principles recognized by the FASB to be applied by nongovernmental entities. The ASC supersedes all existing non-Securities and Exchange Commission accounting and reporting standards. Following the ASC, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, the FASB will issue Accounting Standards Updates, which will serve only to update the ASC. The ASC is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Partnership adopted the requirements of Update 2009-01 to its financial statements on September 30, 2009 and it did not have a material impact on its financial statement disclosures.

In May 2009, the FASB issued ASC 855-10, Subsequent Events (ASC 855-10). ASC 855-10 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The provisions require management of a reporting entity to evaluate events or transactions that may occur after the balance sheet date for potential recognition or disclosure in the financial statements and provides guidance for disclosures that an entity should make about those events. ASC 855-10 is effective for interim or annual financial periods ending after June 15, 2009 and shall be applied prospectively. The Partnership adopted the requirements of this standard on June 30, 2009 and it did not have a material impact to its financial position or results of operations or related disclosures. The adoption of these provisions does not change the Partnership s current practices with respect to evaluating, recording and disclosing subsequent events.

In June 2008, the FASB issued ASC 260-10-45-61A, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (ASC 260-10-45-61A). ASC 260-10-45-61A applies to the calculation of EPU described in previous guidance, for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid)

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

are participating securities and shall be included in the computation of EPU pursuant to the two-class method. ASC 260-10-45-61A is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption was prohibited. The Partnership adopted the requirements on January 1, 2009 and its adoption did not have a material impact on its financial position and results of operations.

In April 2008, the FASB issued ASC 350-30-65-1, Determination of Useful Life of Intangible Assets (ASC 350-30-65-1). ASC 350-30-65-1 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under previous guidance. The intent of ASC 350-30-65-1 is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset. The Partnership adopted the requirements of ASC 350-30-65-1 on January 1, 2009 and its adoption did not have a material impact on its financial position and results of operations.

In March 2008, the FASB issued ASC 260-10-55-103 through 55-110, Application of the Two-Class Method (ASC 260-10-55-103), which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. ASC 260-10-55-103 considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. The Partnership s adoption of ASC 260-10-55-103 on January 1, 2009 impacted its presentation of net income (loss) per common limited partner unit as the Partnership previously presented net income (loss) per common limited partner unit as though all earnings were distributed each quarterly period (see Net Income (Loss) Per Common Unit). The Partnership adopted the requirements of ASC 260-10-55-103 on January 1, 2009 and its adoption did not have a material impact on its financial position and results of operations.

In March 2008, the FASB issued ASC 815-10-50-1, Disclosures about Derivative Instruments and Hedging Activities (ASC 815-10-50-1), to require enhanced disclosure about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The Partnership adopted the requirements of this section of ASC 815-10-50-1 on January 1, 2009 and it did not have a material impact on its financial position or results of operations (see Note 12).

In December 2007, the FASB issued ASC 810-10-65-1, Non-controlling Interests in Consolidated Financial Statements (ASC 810-10-65-1). ASC 810-10-65-1 establishes accounting and reporting standards for the non-controlling interest (minority interest) in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. It also requires consolidated net income to be reported and disclosed on the face of the consolidated statements of operations at amounts that include the amounts attributable to both the parent and the non-controlling interest. Additionally, ASC 810-10-65-1 establishes a single method of accounting for changes in a parent s ownership interest in a subsidiary that does not result in deconsolidation and that the parent recognize a gain or loss in net income when a subsidiary is deconsolidated and adjust its remaining investment, if any, at fair value. The Partnership adopted the requirements of ASC 810-10-65-1on January 1, 2009 and adjusted its presentation of its financial position and results of operations. Prior period financial position and results of operations have been adjusted retrospectively to conform to these provisions.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In December 2007, the FASB issued ASC 805, Business Combinations (ASC 805). ASC 805 retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. ASC 805 requires an acquirer to recognize the assets acquired, liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, at their fair values as of that date, with specified limited exceptions. Additionally, it requires costs incurred in connection with an acquisition be expensed as incurred. Restructuring costs, if any, are to be recognized separately from the acquisition. The acquirer in a business combination achieved in stages must also recognize the identifiable assets and liabilities, as well as the non-controlling interests in the acquiree, at the full amounts of their fair values. The Partnership adopted these requirements on January 1, 2009 and it did not have a material impact on its financial position and results of operations.

Recently Issued Accounting Standards

In January 2010, the FASB issued Accounting Standards Update 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements (Update 2010-06). Update 2010-06 amends Subtopic 820-10, Fair Value Measurements and Disclosures Overall and provides enhanced disclosure requirements for activity in Levels 1, 2 and 3 fair value measurements. The amendment requires significant transfers in and out of Levels 1 and 2 fair value measurements to be reported separately and the reasons for such transfers to be disclosed. Update 2010-06 also requires information regarding purchases, sales, issuances, and settlements to be disclosed separately on a gross basis in the reconciliation of fair value measurements using unobservable inputs for all activity in Level 3 fair value measurements. Additionally, the amendment clarifies that fair value measurement for each class of assets and liabilities must be disclosed as well as disclosures pertaining to the inputs and valuation techniques for both recurring and nonrecurring fair value measurements in Levels 2 and 3. These requirements are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those requirements will be effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The Partnership will apply these requirements upon its adoption on January 1, 2010 and does not expect it to have a material impact on its financial position, results of operations or related disclosures.

NOTE 3 INVESTMENT IN JOINT VENTURE

On May 31, 2009, the Partnership and subsidiaries of Williams completed the formation of Laurel Mountain, a joint venture which owns and operates the Partnership s Appalachia natural gas gathering system, excluding the Partnership s northeastern Tennessee operations. Williams contributed cash of $100.0 million to the joint venture (of which the Partnership received approximately $87.8 million, net of working capital adjustments) and a note receivable of $25.5 million. The Partnership contributed the Appalachia natural gas gathering system and retained a 49% ownership interest in Laurel Mountain. The Partnership is also entitled to preferred distribution rights relating to all payments on the note receivable. Williams obtained the remaining 51% ownership interest in Laurel Mountain.

Upon completion of the transaction, the Partnership recognized its 49% ownership interest in Laurel Mountain as an investment in joint venture on its consolidated balance sheet at fair value. During the year ended December 31, 2009, the Partnership recognized a gain on sale of $108.9 million, including $54.2 million associated with the revaluation of the Partnership s investment in Laurel Mountain to fair value. The Partnership used the net proceeds from the transaction to reduce borrowings under its senior secured credit facility (see Note 14). In addition, Atlas Energy Resources sold two natural gas processing plants and associated pipelines located in southwestern Pennsylvania to Laurel Mountain for

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$10.0 million. In connection with the formation of Laurel Mountain, Laurel Mountain entered into natural gas gathering agreements with Atlas Energy Resources which superseded the existing natural gas gathering agreements and omnibus agreement between the Partnership and Atlas Energy Resources. Under the new gas gathering agreement, Atlas Energy Resources is obligated to pay a gathering fee that is generally the same as the gathering fee required under the terminated agreements, the greater of $0.35 per MCF or 16% of the realized sales price (except that a lower fee applies with respect to specific wells subject to certain existing contracts or in the event Laurel Mountain fails to perform specified obligations). The Partnership has accounted for its ownership interest in Laurel Mountain under the equity method of accounting, with recognition of its ownership interest in the income of Laurel Mountain as equity income on its consolidated statements of operations. As of the year ended December 31, 2009, the Partnership has utilized $1.7 million of the $25.5 million note receivable to make a capital contribution to Laurel Mountain.

NOTE 4 DISCONTINUED OPERATIONS

On May 4, 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE:SEP) (Spectra) for net proceeds of $294.5 million in cash, net of working capital adjustments. The Partnership used the net proceeds from the transaction to reduce borrowings under its senior secured term loan and revolving credit facility (see Note 14). The Partnership accounted for the sale of the NOARK system assets as discontinued operations within its consolidated financial statements and recorded a gain of $51.1 million on the sale of the NOARK assets within income from discontinued operations on its consolidated statements of operations during the year ended December 31, 2009. The following table summarizes the components included within income from discontinued operations on the Partnership s consolidated statements of operations (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Total revenue and other income (loss), net	$ 21,274	$ 62,423	$ 56,587
Total costs and expenses	(9,857)	(41,877)	(25,757)
Earnings of discontinued operations	$ 11,417	$ 20,546	$ 30,830

During the year ended December 31, 2008, the Partnership recognized impairment charges totaling $21.6 million within income from discontinued operations on its consolidated statements of operations in connection with a write-off of costs related to NOARK s pipeline expansion project. The costs incurred consisted of preliminary construction and engineering costs incurred as well as a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the components included within total assets and liabilities of discontinued operations within the Partnership s consolidated balance sheet for the year ended December 31, 2008 (in thousands):

	December 31, 2008
Cash and cash equivalents	$ 75
Accounts receivable	12,365
Prepaid expenses and other	1,001
Total current assets of discontinued operations	13,441
Property, plant and equipment, net	241,926
Other assets, net	239
Total assets of discontinued operations	$ 255,606
Accounts payable	$ 4,120
Accrued liabilities	5,892
Accrued producer liabilities	560
Total current liabilities of discontinued operations	$ 10,572

NOTE 5 COMMON UNIT EQUITY OFFERINGS

In August 2009, the Partnership sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. The Partnership also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2.0% general partner interest in the Partnership. In addition, the Partnership issued warrants granting investors in its private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units. The Partnership utilized the net proceeds from the common unit offering to repay a portion of its indebtedness under its senior secured term loan (see Note 14), and made similar repayments with net proceeds from exercises of the warrants. In January 2010, the Partnership amended the warrants to purchase 2,689,765 common units and all warrants were exercised (see Note 22).

The common units and warrants sold by the Partnership in the August 2009 private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement required the Partnership to (a) file a registration statement with the Securities and Exchange Commission for the privately placed common units and those underlying the warrants by September 21, 2009 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by November 18, 2009. The Partnership filed a registration statement with the Securities and Exchange Commission in satisfaction of the registration requirements of the registration rights agreement on September 3, 2009, and the registration statement was declared effective on October 14, 2009.

In June 2008, the Partnership sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, the Partnership sold 1,112,000 common units to Atlas Energy and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. The Partnership also received a capital contribution from the General Partner of $5.4 million for the General Partner to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements (see Note 12).

In July 2007, the Partnership sold 25,568,175 common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

billion. Of the 25,568,175 common units sold by the Partnership, 3,835,227 common units were purchased by AHD for $168.8 million. The Partnership also received a capital contribution from the General Partner of $23.1 million for the General Partner to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from the sale to partially fund the acquisition of control of the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and a 72.8% ownership interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas. The common units issued were subsequently registered with the Securities and Exchange Commission in November 2007.

NOTE 6 PREFERRED UNIT EQUITY OFFERINGS

Class A Preferred Units

In April 2007, the Partnership and Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, agreed to amend the terms of the then-outstanding 40,000 6.5% cumulative convertible preferred units (Class A Preferred Units) effective as of that date. The terms of the Class A Preferred Units were amended to entitle Sunlight Capital to receive dividends of 6.5% per annum commencing in March 2008 and to be convertible, at Sunlight Capital s option, into common units commencing May 8, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of the Partnership s common units as of the date of the notice of conversion. The Partnership could elect to pay cash rather than issue common units in satisfaction of a conversion request.

The Partnership had the right to call the Class A Preferred Units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.22. If not converted into common units or redeemed prior to the second anniversary of the conversion commencement date, the Class A Preferred Units would automatically be converted into the Partnership s common units in accordance with the agreement. In consideration of Sunlight Capital s consent to the amendment of the Class A Preferred Units, the Partnership issued $8.5 million of its 8.125% senior unsecured notes due 2015 to Sunlight Capital. The Partnership recorded the senior unsecured notes issued as long-term debt and a preferred unit dividend within Partners Capital on its consolidated balance sheet and, during the year ended December 31, 2007, reduced net income (loss) attributable to common limited partners and the General Partner by $3.8 million of this amount, which was the portion deemed to be attributable to the concessions of the common limited partners and the General Partner to the Class A preferred unitholder, on its consolidated statements of operations.

In December 2008, the Partnership redeemed 10,000 of the Class A Preferred Units for $10.0 million in cash under the terms of the agreement (see Note 14). The redemption was classified as a reduction of Class A Preferred Equity within Partners Capital on the Partnership s consolidated balance sheet. The Partnership s 30,000 outstanding Class A preferred limited partner units were convertible into approximately 5,263,158 common limited partner units at December 31, 2008, which is based upon the market value of the Partnership s common units and subject to provisions and limitations within the agreement between the parties, with an estimated fair value of approximately $31.6 million based upon the market value of the Partnership s common units as of that date.

In January 2009, the Partnership and Sunlight Capital agreed to amend certain terms of the Class A Preferred Units. The amendment (a) increased the dividend yield from 6.5% to 12.0% per annum, effective January 1, 2009, (b) established a new conversion commencement date on the outstanding Class A Preferred Units of April 1, 2009, (c) established Sunlight Capital s new conversion option price of $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of the Partnership s common units, and (d) established a new price for the Partnership s call redemption right of $27.25.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The amendment to the preferred units certificate of designation also required that the Partnership issue Sunlight Capital $15.0 million of its 8.125% senior unsecured notes due 2015 (see Note 14) to redeem 10,000 Class A Preferred Units. Management of the Partnership estimated that the fair value of the $15.0 million 8.125% senior unsecured notes issued to redeem the Class A Preferred Units was approximately $10.0 million at the date of redemption based upon the market price of the publicly-traded senior notes. As such, the Partnership recorded the redemption by recognizing a $10.0 million reduction of Class A Preferred equity within Partners Capital, $15.0 million of additional long-term debt for the face value of the senior unsecured notes issued, and a $5.0 million discount on the issuance of the senior unsecured notes which is presented as a reduction of long-term debt on the Partnership s consolidated balance sheet. The discount recognized upon issuance of the senior unsecured notes will be amortized to interest expense within the Partnership s consolidated statements of operations over the term of the notes based upon the effective interest rate method.

The amendment to the preferred units certificate of designation also required that (a) the Partnership redeem 10,000 of the Class A Preferred Units for cash at the liquidation value on April 1, 2009 and (b) that if Sunlight Capital made a conversion request of the remaining 10,000 Class A Preferred Units between April 1, 2009 and June 1, 2009, the Partnership has the option of redeeming the Class A Preferred Units for cash at the stipulated liquidation value or converting the Class A Preferred Units into its common limited partner units at the stipulated conversion price. If Sunlight Capital made a conversion request subsequent to June 1, 2009, 5,000 of the 10,000 Class A Preferred Units would have been required to be redeemed in cash, while the Partnership had the option of redeeming the remaining 5,000 Class A Preferred Units in cash or converting the preferred units into its common limited partner units.

On April 1, 2009, the Partnership redeemed 10,000 of the Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $10.0 million, in accordance with the terms of the amended preferred units certificate of designation. Additionally on April 1, 2009, the Partnership paid Sunlight a preferred dividend of $0.3 million, representing the quarterly dividend on the 10,000 preferred units held by Sunlight prior to the Partnership s redemption. On April 13, 2009, the Partnership converted 5,000 of the Class A Preferred Units into 1,465,653 Partnership common units in accordance with the terms of the amended preferred units certificate of designation. The Partnership reclassified $5.0 million from Class A preferred limited partner equity to common limited partner equity within Partners Capital when these preferred units were converted into common limited partner units. On May 5, 2009, the Partnership redeemed the remaining 5,000 Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $5.0 million, pursuant to the terms of the amended preferred units certificate of designation. Additionally, on May 5, 2009, the Partnership paid Sunlight a preferred dividend of $0.2 million, representing the quarterly dividend on the 5,000 Class A Preferred Units held by Sunlight prior to the Partnership s redemption.

Dividends previously paid on the Class A Preferred Units and the premium paid upon their redemption, were recognized as a reduction to the Partnership s net income (loss) in determining net income (loss) attributable to common unitholders and the General Partner.

In accordance with Securities and Exchange Commission Staff Accounting Bulletin No. 68, Increasing Rate Preferred Stock, the initial issuances of the 40,000 Class A Preferred Units were recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. As a result of an amendment to the preferred units certificate of designation in March 2007, the Partnership, in lieu of dividend payments to Sunlight Capital, recognized an imputed dividend cost of $2.5 million that was amortized over a twelve-month period commencing March 2007 and was based upon the present value of the net proceeds received using the then 6.5% stated dividend yield. During the

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

twelve months ended December 31, 2008, the Partnership amortized the remaining $0.5 million of this imputed dividend cost, which is presented as an additional adjustment of net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations for the year ended December 31, 2008.

The Partnership recognized $0.4 million and $1.8 million of preferred dividend cost for the years ended December 31, 2009 and 2008, respectively, for dividends paid to the Class A preferred units, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations.

Class B Preferred Units

In December 2008, the Partnership sold 10,000 newly-created Class B Preferred Units (the Class B Preferred Units) to AHD for cash consideration of $1,000 per Class B Preferred Unit (the Face Value) pursuant to a certificate of designation (the Class B Preferred Units Certificate of Designation). On March 30, 2009, AHD, pursuant to rights within the Class B Preferred Unit Purchase Agreement, purchased an additional 5,000 Class B Preferred Units at Face Value for net proceeds of $5.0 million. The Partnership used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for the Partnership s common units. The record date of determination for holders entitled to receive distributions of the Class B Preferred Units will be the same as the record date of determination for common unit holders entitled to receive quarterly distributions. Additionally, on March 30, 2009, the Partnership and AHD agreed to amend the terms of the Class B Preferred Units Certificate of Designation to remove the conversion feature, thus the Class B Preferred Units are not convertible into common units of the Partnership. The amended Class B Preferred Units Certificate of Designation also gives the Partnership the right at any time to redeem some or all of the outstanding Class B Preferred Units for cash at an amount equal to the Class B Preferred Unit Liquidation Value being redeemed, provided that such redemption must be exercised for no less than the lesser of a) 2,500 Class B Preferred Units or b) the number of remaining outstanding Class B Preferred Units.

The cumulative sale of the Class B Preferred Units to AHD was exempt from the registration requirements of the Securities Act of 1933. The Partnership recognized $0.5 million of preferred dividend cost for the year ended December 31, 2009, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations. The Class B Preferred Units are reflected on the Partnership s consolidated balance sheet as Class B preferred equity within Partners Capital.

NOTE 7 INVESTMENT IN ATLAS PIPELINE HOLDINGS II, LLC

In June 2009, the Partnership purchased 15,000 12.0% cumulative preferred units (the preferred units) from a newly-formed subsidiary of AHD, Atlas Pipeline Holdings II, LLC (AHD II) for cash consideration of $1,000 per unit, for an aggregate investment of $15.0 million at December 31, 2009. The preferred units receive cash distributions of 12.0% per annum, to be paid quarterly. However, per the terms of AHD s amended agreement to its outstanding revolving credit facility, such distributions can be paid only upon AHD s repayment of all of its outstanding borrowings under its credit facility. The credit facility s maturity date is April 13, 2010. Distributions on the Partnership s preferred units held by AHD II prior to AHD s repayment of all indebtedness under its credit facility will be paid by increasing the Partnership s preferred unit investment in AHD II. AHD II has the option, beginning on April 14, 2010, to redeem all of its outstanding preferred units held by the Partnership for an amount equal to the Partnership s then-current balance of its preferred unit investment. AHD used the proceeds from its preferred unit offering to the Partnership to reduce indebtedness under its credit facility. The Partnership accounted for the purchase of the preferred units as treasury units, with the investment reflected at cost as a reduction of Partners Capital within its consolidated balance sheet

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of its available cash (as defined in its partnership agreement) for that quarter to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and General Partner distributions declared by the Partnership for the period from January 1, 2007 through December 31, 2009 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 14, 2007	December 31, 2006	$ 0.86	$ 11,249	$ 4,193
May 15, 2007	March 31, 2007	$ 0.86	$ 11,249	$ 4,193
August 14, 2007	June 30, 2007	$ 0.87	$ 11,380	$ 4,326
November 14, 2007	September 30, 2007	$ 0.91	$ 35,205	$ 4,498
February 14, 2008	December 31, 2007	$ 0.93	$ 36,051	$ 5,092
May 15, 2008	March 31, 2008	$ 0.94	$ 36,450	$ 7,891
August 14, 2008	June 30, 2008	$ 0.96	$ 44,096	$ 9,308
November 14, 2008	September 30, 2008	$ 0.96	$ 44,105	$ 9,312
February 13, 2009	December 31, 2008	$ 0.38	$ 17,463	$ 358
May 15, 2009	March 31, 2009	$ 0.15	$ 7,149	$ 147

The Partnership did not declare a cash distribution for the quarters ended December 31, September 30 and June 30, 2009. On May 29, 2009, the Partnership entered into an amendment to its senior secured credit facility (see Note 14) which, among other changes, required that it pay no cash distributions from the time it entered into the amendment through the end of 2009. Commencing with the quarter ending March 31, 2010, cash distributions can be paid, only if the Partnership s senior secured leverage ratio meets certain thresholds and it has minimum liquidity (both as defined in the credit agreement) of at least $50.0 million.

In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems in July 2007, the General Partner, which holds all of the incentive distribution rights in the Partnership, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. The General Partner also agreed that the resulting allocation of incentive distribution rights back to the Partnership would be after the General Partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter (the IDR Adjustment Agreement).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 9 PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2009	December 31, 2008[(1)]	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,658,282	$ 1,707,046	2 40
Rights of way	167,048	168,057	20 40
Buildings	8,920	8,920	40
Furniture and equipment	9,538	9,279	3 7
Other	12,849	13,002	3 10
	1,856,637	1,906,304	
Less accumulated depreciation	(172,253)	(125,293)	
	$ 1,684,384	$ 1,781,011	

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4).

On July 13, 2009, the Partnership sold a natural gas processing facility and a one-third undivided interest in other associated assets located in its Mid-Continent operating segment for approximately $22.6 million in cash. The facility was sold to Penn Virginia Resource Partners, L.P. (NYSE: PVR), who will provide natural gas volumes to the facility and reimburse the Partnership for its proportionate share of the operating expenses. The Partnership will continue to operate the facility. The Partnership used the proceeds from this transaction to reduce outstanding borrowings under its senior secured credit facility (see Note 14). The Partnership recognized a gain on sale of $2.5 million, which is recorded within gain on asset sales on the Partnership s consolidated statements of operations.

NOTE 10 OTHER ASSETS

The following is a summary of other assets (in thousands):

	December 31, 2009	December 31, 2008[(1)]
Deferred finance costs, net of accumulated amortization of $25,314 and $17,298 at December 31, 2009 and 2008, respectively	$ 27,331	$ 23,676
Long-term pipeline lease prepayment	3,168	
Security deposits	3,494	1,317
	$ 33,993	$ 24,993

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4).

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 14). During the years ended December 31, 2009 and 2008 the Partnership recorded $2.5 million in each year related to accelerated amortization of deferred financing costs associated with the retirement of a portion of its term loan. Total amortization expense of deferred finance costs was $8.0 million, $5.9 million and $7.4 million for the years ended December 31, 2009, 2008 and 2007, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations. Amortization expense related to deferred finance costs is estimated to be as follows for each of the next five calendar years: 2010 to 2012 - $6.2 million; 2013 - $4.4 million; 2014 - $1.7 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11 ACQUISITIONS

Chaney Dell and Midkiff/Benedum

In July 2007, the Partnership acquired control of Anadarko s 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). The transaction was accomplished through the formation of two joint venture companies which own the respective systems, to which the Partnership contributed $1.9 billion and Anadarko contributed the Anadarko Assets.

The Partnership funded the purchase price in part from the private placement of 25,568,175 common limited partner units at a negotiated purchase price of $44.00 per unit, generating gross proceeds of $1.125 billion. Of the $1.125 billion, $168.8 million of these units were purchased by AHD. The Partnership funded the remaining purchase price from $830.0 million of proceeds from a senior secured term loan which matures in July 2014 and borrowings from its senior secured revolving credit facility that matures in July 2013 (see Note 14). The General Partner, which holds all of the incentive distribution rights in the Partnership, has also agreed to allocate a portion of its incentive distribution rights back to the Partnership as set forth in the IDR Adjustment Agreement (see Note 8).

In connection with this acquisition, the Partnership reached an agreement with Pioneer, which currently holds a 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer had options to buy up to an additional 22% interest in the Midkiff/Benedum system. These options expired on November 2, 2009.

The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in the acquisition, based on their fair values at the date of the acquisition (in thousands):

Accounts receivable	$ 745
Prepaid expenses and other	4,587
Property, plant and equipment	1,030,464
Intangible assets customer relationships	205,312
Goodwill	613,420
Total assets acquired	1,854,528
Accounts payable and accrued liabilities	(1,499)
Net cash paid for acquisition	$ 1,853,029

The Partnership initially recorded goodwill in connection with this acquisition as a result of Chaney Dell s and Midkiff/Benedum s significant cash flow and strategic industry position. The Partnership tested its goodwill for impairment at December 31, 2008 and recognized an impairment charge of $676.9 million during the year ended December 31, 2008, which included the amounts recognized in connection with its Chaney Dell and Midkiff/Benedum acquisitions (see Goodwill in Note 2).

In April 2008, the Partnership received a $30.2 million cash reimbursement for state sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the sales tax paid in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition. The results of Chaney Dell s and Midkiff/Benedum s operations are included within the Partnership s consolidated financial statements from the date of acquisition.

NOTE 12 DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps and options, in connection with its commodity price and interest rate risk management activities. The Partnership enters into financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. It also enters into financial swap instruments to hedge certain portions of its floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. Under its swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Commodity-based 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.

During December 2007, the Partnership discontinued hedge accounting for crude oil derivative instruments covering certain forecasted condensate production for 2008 and other future periods, and then documented these derivative instruments to match certain forecasted NGL production for the respective periods. The discontinuation of hedge accounting for these instruments with regard to the Partnership s condensate production resulted in a $12.6 million non-cash derivative loss recognized within other income (loss), net in its consolidated statements of operations and a corresponding decrease in accumulated other comprehensive loss in Partners Capital in its consolidated balance sheet for the year ended December 31, 2007.

On July 1, 2008, the Partnership discontinued hedge accounting for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. The fair value of these commodity derivative instruments at June 30, 2008, which was recognized in accumulated other comprehensive loss within Partners Capital on the Partnership s consolidated balance sheet, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, the Partnership recognizes changes in fair value within other income (loss), net in its consolidated statements of operations as they occur.

At December 31, 2009, the Partnership had interest rate derivative contracts having aggregate notional principal amounts of $450.0 million. Under the terms of these agreements, the Partnership will pay weighted average interest rates of 3.0%, plus the applicable margin as defined under the terms of its credit facility (see Note 14), and will receive LIBOR, plus the applicable margin, on the notional principal amounts. The interest rate swap agreements were in effect as of December 31, 2009 and expire during periods ranging from January 30, 2010 through April 30, 2010. Beginning May 29, 2009, the Partnership discontinued hedge accounting for its interest rate derivatives which were qualified as hedges. As such, subsequent changes in the fair value of these derivatives will be recognized immediately within other income (loss), net in its consolidated statements of operations. The fair value of these derivative instruments at May 29, 2009, which was recognized in accumulated other comprehensive loss within Partners Capital on the Partnership s consolidated balance sheet, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged interest rates affect earnings. For non-qualifying derivatives, the Partnership recognizes changes in fair value within other income (loss), net in its consolidated statements of operations as they occur.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. At December 31, 2009 and 2008, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $43.3 million and $63.6 million, respectively. Of the $49.2 million of net loss in accumulated other comprehensive loss within Partners Capital on the Partnership s consolidated balance sheet at December 31, 2009, the Partnership will reclassify $28.2 million of losses to the Partnership s consolidated statements of operations over the next twelve month period, consisting of $26.0 million of losses to natural gas and liquids revenue and $2.2 million of losses to interest expense. Aggregate losses of $21.0 million will be reclassified to the Partnership s consolidated statements of operations in later periods, all consisting of losses to natural gas and liquids revenue. At December 31, 2009, no derivative instruments are designated as hedges for hedge accounting purposes.

The fair value of the Partnership s derivative instruments was included in its consolidated balance sheets as follows (in thousands):

	December 31, 2009	December 31, 2008
Current portion of derivative asset	$ 998	$ 44,961
Long-term derivative asset	361	
Current portion of derivative liability	(33,547)	(60,396)
Long-term derivative liability	(11,126)	(48,159)
	$ (43,314)	$ (63,594)

The following table summarizes the Partnership s gross fair values of derivative instruments for the period indicated (in thousands):

	Asset Derivatives			Liability Derivatives		
		December 31,			December 31,	
	Balance Sheet Location	2009	2008	Balance Sheet Location	2009	2008
Interest rate contracts	N/A	$	$	Current portion of derivative liability	$ (2,247)	$ (9,965)
Interest rate contracts	N/A			Current portion of derivative asset	(593)	
Interest rate contracts	N/A			Long-term derivative liability		(1,762)
Commodity contracts	Current portion of derivative asset	1,591	44,961	Current portion of derivative asset		
Commodity contracts	Long-term derivative asset	361		Long-term derivative asset		
Commodity contracts	Current portion of derivative liability	6,562	7,723	Current portion of derivative liability	(37,862)	(58,154)
Commodity contracts	Long-term derivative liability	3,435	3,505	Long-term derivative liability	(14,561)	(49,902)
		$ 11,949	$ 56,189		$ (55,263)	$ (119,783)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2009, the Partnership had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Interest Fixed-Rate Swaps

Term	Amount	Type		Fair Value(1) Asset/ (Liability) (in thousands)
January 2008-January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	$ (438)
April 2008-April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	(2,402)
Total Interest Rate Swaps				$ (2,840)

Fixed Price Swaps

Production Period	Purchased/ Sold	Commodity	Volumes(2)	Average Fixed Price	Fair Value(1) Asset/ (Liability) (in thousands)
2010	Purchased	Natural Gas	4,380,000	$ 8.635	$ (13,306)
2010	Sold	Natural Gas Basis	4,500,000	(0.638)	(1,936)
2010	Purchased	Natural Gas Basis	8,880,000	(0.597)	3,369
2011	Sold	Natural Gas Basis	1,920,000	(0.728)	(845)
2011	Purchased	Natural Gas Basis	1,920,000	(0.758)	903
2012	Sold	Natural Gas Basis	720,000	(0.685)	(269)
2012	Purchased	Natural Gas Basis	720,000	(0.685)	269
Total Fixed Price Swaps					$ (11,815)

NGL Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes(2)	Average Strike Price	Fair Value(1) Asset/ (Liability) (in thousands)
2010	Purchased	Put	Propane	35,910,000	$ 1.022	$ 1,137
2010	Purchased	Put	Normal Butane	3,654,000	1.205	29
2010	Purchased	Put	Natural Gasoline	3,906,000	1.545	102
Total NGL Options						$ 1,268

Crude Oil Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes[2]	Average Strike Price	Fair Value[1] Asset/ (Liability) (in thousands)
2010	Purchased	Put	Crude Oil	897,000	73.12	$ 3,518
2010	Sold	Call	Crude Oil	3,361,500	81.23	(23,183)
2010	Purchased[3]	Call	Crude Oil	714,000	120.00	430
2011	Sold	Call	Crude Oil	678,000	94.68	(6,687)
2011	Purchased[3]	Call	Crude Oil	252,000	120.00	1,017
2012	Sold	Call	Crude Oil	498,000	95.83	(6,197)
2012	Purchased[3]	Call	Crude Oil	180,000	120.00	1,175
Total Crude Options						$ (29,927)
Total Fair Value						$ (43,314)

(1) See Note 13 for discussion on fair value methodology.

(2) Volumes for Natural Gas are stated in MMBTU s. Volumes for NGLs are stated in gallons. Volumes for Crude Oil are stated in barrels.

(3) Calls purchased for 2010 through 2012 represent offsetting positions for calls sold. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the years ended December 31, 2009 and 2008, the Partnership made net payments of $5.0 million and $274.0 million, respectively, related to the early termination of derivative contracts. The majority of these derivative contracts were put into place simultaneously with the Partnership s acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. Additional terminated derivative contracts extend through the fourth quarter of 2012. During the years ended December 31, 2009, 2008 and 2007, the Partnership recognized the following derivative activity related to the early termination of these derivative instruments within its consolidated statements of operations (in thousands):

Early termination of derivative contracts

	For the Years Ended December 31, 2009	2008	2007
Cash paid for early termination	$ (5,000)	$ (273,987)	$
Less: Deferred recognition of loss on early termination[(1)]		(76,345)	
	(5,000)	(197,642)	
Net cash derivative expense included within natural gas and liquids revenue		2,322	
Net cash derivative expense included within other loss, net	(5,000)	(199,964)	
Recognition of deferred hedge loss from prior periods included within natural gas and liquids revenue	(68,479)	(32,389)	
Recognition of deferred hedge gain (loss) from prior periods included within other income (loss), net	44,861	(39,218)	
Total recognized loss from early termination	$ (28,618)	$ (269,249)	$

(1) Deferred recognition based upon effective portion of hedges deferred to OCI, plus theoretical premium related to unwound options which had previously been purchased or sold as part of costless collars

In addition, the Partnership will recognize $14.6 million, $2.3 million and $2.0 million of income in years 2010, 2011 and 2012, respectively, the remaining period for which the hedged physical transactions are scheduled to be settled, in the Partnership s consolidated statements of operations. This $18.9 million includes $23.5 million of income related to the theoretical premiums for unwound options which had previously been purchased or sold as part of costless collars, with an offsetting expense of $4.6 million which will be reclassified from accumulated other comprehensive loss within Partners Capital on the Partnership s consolidated balance sheet.

The following table summarizes the Partnership s total derivative activity for the periods indicated including the amounts shown above (in thousands):

	Years Ended December 31, 2009	2008	2007
Cash settlements:			
Gain (loss) from cash settlement of effective portion of qualifying commodity derivatives[(1)]	$ 22,211	$ (49,268)	$ (48,601)
Loss from cash settlement of ineffective portion of qualifying commodity derivatives[(1)]	(123)	(23,359)	(792)

Loss from cash settlement of qualifying interest rate derivatives(2)	(11,754)	(1,226)	
Loss from cash settlement of non-qualifying/ineffective commodity derivatives(3)	(53,699)	(211,636)	(10,158)
Loss from cash settlement of non-qualifying interest rate derivatives(3)	(443)		
Total loss from cash settlements	$ (43,808)	$ (285,489)	$ (59,551)
Non-cash gain (loss)			
Loss from recognition of effective portion of qualifying commodity derivatives settled in a prior period (1)	(68,479)	(32,389)	
Gain from non-cash recognition of non-qualifying derivatives settled in a prior period(2)(4)	44,861	(39,218)	
Gain (loss) from change in market value of non-qualifying and ineffective commodity derivatives(2)	(27,126)	187,374	(169,424)
Loss from change in market value of non-qualifying interest rate derivatives (2)	(598)		
Total non-cash gain (loss)	$ (51,342)	$ 115,767	$ (169,424)
Total derivative loss	$ (95,150)	$ (169,722)	$ (228,975)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.
(2) Included within interest expense on the Partnership s consolidated statements of operations.
(3) Included within other income (loss), net on the Partnership s consolidated statements of operations.
(4) Non-Cash recognition of non-qualifying derivatives includes the theoretical premium related to calls sold in conjunction with puts purchased in costless collars in which the puts were sold as part of the equity unwinds in 2008.

The following tables summarize the gross effect of derivative instruments on the Partnership s consolidated statements of operations for the period indicated (in thousands):

	Gain (Loss) Recognized in Accumulated OCI Years ended December 31,				Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Years ended December 31,		
	2009	2008	2007	Location	2009	2008	2007
Interest rate contracts[1]	$ (2,268)	$ (12,953)	$	Interest expense	$ (11,754)	$ (1,226)	$
Commodity contracts[1]		(112,824)	(101,176)	Natural gas and liquids revenue	(46,268)	(81,657)	(48,601)
Commodity contracts[3]				Other income (loss), net			(12,611)
	$ (2,268)	$ (125,777)	$ (101,176)		$ (58,022)	$ (82,883)	$ (61,212)

		Gain (Loss) Recognized in Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) Years ended December 31,		
	Location	2009	2008	2007
Interest rate contracts[1]	Other income (loss), net	$ (1,041)	$	$
Commodity contracts[1]	Natural gas and liquids revenue	(123)	(23,359)	(792)
Commodity contracts[1]	Other income (loss), net		(263,977)	(4,093)
Commodity contracts[2]	Other income (loss), net	(35,964)	200,497	(162,877)
		$ (37,128)	$ (86,839)	$ (167,762)

(1) Hedges previously designated as cash flow hedges
(2) Dedesignated cash flow hedges and non-designated hedges
(3) Reclass out of OCI resulting from dedesignation of hedge due to probability of future physical transaction not occurring

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 13 FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Instruments

FASB ASC has established a hierarchy to measure its 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.

The Partnership uses a fair value methodology to value the assets and liabilities for its respective outstanding derivative contracts (see Note 12). At December 31, 2009, all of the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and NGL options. The Partnership s Level 2 commodity derivatives are calculated based on observable market data related to the change in price of the underlying commodity. The Partnership s interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for the Partnership s NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations, and therefore are defined as Level 3. Valuations for the Partnership s NGL options are based on forward price curves developed by the related financial institutions, and therefore are defined as Level 3.

On June 30, 2009, the Partnership changed the basis for its valuation of crude oil options. Previously, the Partnership utilized forward price curves developed by its derivative counterparties. Effective June 30, 2009, the Partnership utilized crude oil option prices quoted from a public commodity exchange. With this change in valuation basis, the Partnership reclassified the inputs for the valuation of its crude oil options from a Level 3 input to a Level 2 input. The change in valuation basis did not materially impact the fair value of its derivative instruments on its consolidated statements of operations.

The following table represents the Partnership s assets and liabilities recorded at fair value as of December 31, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total
Commodity-based derivatives	$	$ (41,742)	$ 1,268	$ (40,474)
Interest rate swap-based derivatives		(2,840)		(2,840)
Total	$	$ (44,582)	$ 1,268	$ (43,314)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments for the years ended December 31, 2009 and 2008 (in thousands):

	NGL Fixed Price Swaps	NGL Sales Options	Crude Oil Options	Total
Balance December 31, 2008	$ 1,509	$ 12,316	$ (23,436)	$ (9,611)
New contracts	(1,593)	(9,462)		(11,055)
Cash settlements from unrealized gain (loss)(1)	(5,527)	(7,065)	(37,671)	(50,263)
Cash settlements from other comprehensive income(2)	7,153		11,618	18,771
Net change in unrealized gain (loss)(1)	(1,542)	(1,090)	14,886	12,254
Deferred option premium recognition		6,569	2,239	8,808
Transfer to Level 2			32,364	32,364
Balance December 31, 2009	$	$ 1,268	$	$ 1,268

(1) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.
(2) Included within other income (loss), net on the Partnership s consolidated statements of operations.

Other Financial Instruments

The estimated fair value of the Partnership s other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts that the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership s current assets and liabilities on its consolidated balance sheets, other than the derivatives discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature. The estimated fair values of the Partnership s total debt at December 31, 2009 and 2008, which consists principally of the term loan, the Senior Notes and borrowings under the credit facility, were $1,194.2 million and $1,153.2 million, respectively, compared with the carrying amounts of $1,254.2 million and $1,493.4 million, respectively. The term loan and Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

NOTE 14 DEBT

Total debt consists of the following (in thousands):

	December 31, 2009	December 31, 2008
Revolving credit facility	$ 326,000	$ 302,000
Term loan	433,505	707,180
8.125% Senior notes due 2015	271,628	261,197
8.75% Senior notes due 2018	223,050	223,050

Total debt	1,254,183	1,493,427
Less current maturities		
Total long-term debt	$ 1,254,183	$ 1,493,427

Term Loan and Credit Facility

At December 31, 2009, the Partnership has a senior secured credit facility with a syndicate of banks which consisted of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at the Partnership s option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin).

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The weighted average interest rate on the outstanding revolving credit facility borrowings at December 31, 2009 was 6.8%, and the weighted average interest rate on the outstanding term loan borrowings at December 31, 2009 was 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $10.1 million was outstanding at December 31, 2009. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet. At December 31, 2009, the Partnership has $43.9 million of remaining committed capacity under its credit facility, subject to covenant limitations.

On May 29, 2009, the Partnership entered into an amendment to its credit facility agreement which, among other changes:

- increased the applicable margin above adjusted LIBOR to either (i) the federal funds rate plus 0.5% or (ii) the Wachovia Bank prime rate upon which borrowings under the credit facility bear interest;
- for borrowings under the credit facility that bear interest at LIBOR plus the applicable margin, set a floor for the adjusted LIBOR interest rate of 2.0% per annum;
- increased the maximum ratio of total funded debt (as defined in the credit agreement) to consolidated EBITDA (as defined in the credit agreement; the leverage ratio) and decreased the minimum ratio of interest coverage (as defined in the credit agreement) that the credit facility requires the Partnership to maintain;
- instituted a maximum ratio of senior secured funded debt (as defined in the credit agreement) to consolidated EBITDA (the senior secured leverage ratio) that the credit facility requires the Partnership to maintain;
- required that the Partnership pay no cash distributions during the remainder of the year ended December 31, 2009 and allows the Partnership to pay cash distributions commencing with the quarter ending March 31, 2010, only if its senior secured leverage ratio is less than 2.75x and has minimum liquidity (as defined in the credit agreement) of at least $50.0 million;
- generally limits the Partnership s annual capital expenditures to $95.0 million for the remainder of fiscal 2009 and $70.0 million each year thereafter, unless certain covenants are achieved;
- generally limits the Partnership s annual capital contributions to Laurel Mountain to $10.0 million provided that if less than $10.0 million is paid in any given year that the shortfall may be carried over to the following year;
- permitted the Partnership to retain (i) up to $135.0 million of net cash proceeds from dispositions completed in fiscal 2009 for reinvestment in similar replacement assets within 360 days, and (ii) up to $50.0 million of net cash proceeds from dispositions completed in any subsequent fiscal year subject to certain limitations as defined within the credit agreement; and

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

instituted a mandatory repayment requirement of the outstanding senior secured term loan from excess cash flow (as defined in the credit agreement) based upon the Partnership s leverage ratio.

In June 2008, the Partnership entered into an amendment to the credit facility agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to its early termination of certain derivative contracts (see Note 12) in calculating Consolidated EBITDA. Pursuant to this amendment, in June 2008, the Partnership repaid $122.8 million of its outstanding term loan and repaid $120.0 million of outstanding borrowings under the revolving credit facility with proceeds from its issuance of $250.0 million of 10-year 8.75% senior unsecured notes (see Note 14 Senior Notes). Additionally, pursuant to this amendment, in June 2008 the Partnership s lenders increased their commitments for the revolving credit facility by $80.0 million to $380.0 million.

Borrowings under the credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, except for the assets owned by Chaney Dell and Midkiff/Benedum joint ventures and Laurel Mountain; and by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is also unable to borrow under its credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement. The Partnership is in compliance with these covenants as of December 31, 2009.

The events which constitute an event of default for the credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner. The credit facility requires the Partnership to maintain the following ratios:

Fiscal quarter ending:	Maximum Leverage Ratio	Maximum Senior Secured Leverage Ratio	Minimum Interest Coverage Ratio
December 31, 2009	8.50x	5.25x	1.70x
March 31, 2010	9.25x	5.75x	1.40x
June 30, 2010	8.00x	5.00x	1.65x
September 30, 2010	7.00x	4.25x	1.90x
December 31, 2010	6.00x	3.75x	2.20x
Thereafter	5.00x	3.00x	2.75x

As of December 31, 2009, the Partnership s leverage ratio was 5.2 to 1.0, its senior secured leverage ratio was 3.2 to 1.0, and its interest coverage ratio was 2.5 to 1.0.

Senior Notes

At December 31, 2009, the Partnership had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal

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amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with a net $3.9 million of unamortized discount as of December 31, 2009. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, the Partnership may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its credit facility.

In December 2008, the Partnership repurchased approximately $60.0 million in face amount of its Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million in face amount of the Partnership s 8.125% Senior Notes and approximately $27.0 million in face amount of its 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue.

In January 2009, the Partnership issued Sunlight Capital $15.0 million of its 8.125% Senior Notes to redeem 10,000 Class A Preferred Units (see Note 6). Management of the Partnership estimated that the fair value of the $15.0 million 8.125% Senior Notes issued was approximately $10.0 million at the date of issuance based upon the market price of the publicly-traded Senior Notes. As such, the Partnership recognized a $5.0 million discount on the issuance of the Senior Notes, which is presented as a reduction of long-term debt on its consolidated balance sheets. The discount recognized upon issuance of the Senior Notes will be amortized to interest expense within the Partnership s consolidated statements of operations over the term of the 8.125% Senior Notes based upon the effective interest rate method.

In connection with the issuance of the 8.75% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If the Partnership did not meet the aforementioned deadline, the 8.75% Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that the Partnership had caused the exchange offer to be consummated. On November 21, 2008, the Partnership filed an exchange offer registration statement for the 8.75% Senior Notes with the Securities and Exchange Commission, which was declared effective on December 16, 2008. The exchange offer was consummated on January 21, 2009, thereby fulfilling all of the requirements of the 8.75% Senior Notes registration rights agreement by the specified dates.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. The Partnership is in compliance with these covenants as of December 31, 2009.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Years Ended December 31:	
2010	
2011	
2012	
2013	326,000
2014	433,505
Thereafter	494,678
	$ 1,254,183

Cash payments for interest related to debt were $90.7 million, $86.1 million and $56.3 million for the years ended December 31, 2009, 2008 and 2007, respectively.

NOTE 15 COMMITMENTS AND CONTINGENCIES

The Partnership has noncancelable operating leases for equipment and office space that expire at various dates. Certain operating leases provide the Partnership with the option to renew for additional periods. Where operating leases contain escalation clauses, rent abatements, and/or concessions, the Partnership applies them in the determination of straight-line rent expense over the lease term. Leasehold improvements are amortized over the shorter of the lease term or asset life, which may include renewal periods where the renewal is reasonably assured, and is included in the determination of straight-line rent expense. Total rental expense for the years ended December 31, 2009, 2008 and 2007 was $8.5 million, $9.1 million and $5.1 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2009 is as follows (in thousands):

Years Ended December 31:	
2010	4,547
2011	3,916
2012	3,574
2013	1,512
2014	
Thereafter	
	$ 13,549

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on its financial condition or results of operations.

The Partnership s predecessor with respect to the Chaney Dell assets was named as a defendant in a set of lawsuits filed in 1999 named *Will Price, et al. v. Gas Pipelines and Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas. The lawsuits allege various claims related to industry-wide under reporting of volumes and heating value of natural gas. The plaintiffs currently seek certification of a class of royalty owners on non-federal and non-Native American lands in Kansas, Wyoming and Colorado. The Partnership conducts limited operations in Kansas. Motions for class certification were argued in March 2005. In September 2009, the motions were denied. Plaintiffs have filed a motion for reconsideration that was argued in February 2010. The plaintiffs seek unspecified monetary damages (along with interest, expenses and punitive damages) and injunctive relief with regard to future gas measurement practices. At this stage, discovery has not been conducted with respect to the merits of these lawsuits and the Partnership s liability, if any, will arise under the indemnity provisions of agreements with its predecessor. As such, it is not currently possible to evaluate the likelihood or extent of an unfavorable outcome.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On February 26, 2010, the Partnership received notice from Williams, its partner in Laurel Mountain (see Note 3), alleging that certain title defects exist with respect to the real property contributed by the Partnership to Laurel Mountain. Under the Formation and Exchange Agreement with Williams: (i) Williams had nine (9) months after closing (the Claim Date) to assert any alleged title defects, and (ii) the Partnership has 30 days following the Claim Date to contest the title defects asserted by Williams and 180 days following the Claim Date to cure those title defects. At the end of the cure period with respect to any remaining title defects, the Partnership may elect, at its option, to pay Williams for the cost of such defects, up to a total of $3.5 million, or indemnify Williams with respect to such title defects. The Partnership is conducting a review with respect to the title defects that have been alleged. Although an adverse outcome is reasonably possible, it is not currently possible to evaluate the amount that the Partnership may be required to pay with respect to such alleged title defects.

NOTE 16 CONCENTRATIONS OF CREDIT RISK

The Partnership sells natural gas and NGLs under contract to various purchasers in the normal course of business. For the year ended December 31, 2009, the Partnership had two customers that individually accounted for approximately 53% and 12% of the Partnership s consolidated total third party revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2008, the Partnership had two customers that individually accounted for approximately 52% and 13% of the Partnership s consolidated total third party revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2007, the Partnership had one customer that individually accounted for approximately 56% of the Partnership s consolidated total third party revenues, excluding the impact of all financial derivative activity. Additionally, the Partnership had two customers that individually accounted for approximately 56% and 19% of the Partnership s consolidated accounts receivable at December 31, 2009, and one customer that individually accounted for approximately 42% of the Partnership s consolidated accounts receivable at December 31, 2008.

The Partnership has certain producers which supply a majority of the natural gas to its Mid-Continent gathering systems and processing facilities. A reduction in the volume of natural gas that any one of these producers supply to the Partnership could adversely affect its operating results unless comparable volume could be obtained from other producers in the surrounding region.

The Partnership places its temporary cash investments in high quality short-term money market instruments and deposits with high quality financial institutions. At December 31, 2009, the Partnership and its subsidiaries had $5.8 million in deposits at banks, of which $4.3 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

NOTE 17 BENEFIT PLANS

Generally, all share-based payments to employees, which are not cash settled, including grants of employee stock options, are recognized in the financial statements based on their fair values on the date of the grant.

The Partnership has a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner s affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by the General Partner s managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Partnership Phantom Units. A phantom unit entitles a grantee to receive a common unit, without payment of an exercise price, upon vesting of the phantom unit. In addition, the Committee may grant a participant a distribution equivalent right (DER), which is the right to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. A unit option entitles the grantee to purchase the Partnership s common limited partner units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through December 31, 2009, phantom units granted under the LTIP generally had vesting periods of four years. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined in the LTIP. Of the units outstanding under the LTIP at December 31, 2009, 28,961 units will vest within the following twelve months. All phantom units outstanding under the LTIP at December 31, 2009 include DERs granted to the participants by the Committee. The amounts paid with respect to LTIP DERs were $0.1 million, $0.5 million and $0.6 million for the years ended December 31, 2009, 2008 and 2007, respectively. These amounts were recorded as reductions of Partners Capital on the Partnership s consolidated balance sheet.

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

	Years Ended December 31,		
	2009	2008	2007
Outstanding, beginning of year	126,565	129,746	159,067
Granted[1]	2,000	54,796	25,095
Matured[2]	(58,257)	(56,227)	(51,166)
Forfeited	(18,075)	(1,750)	(3,250)
Outstanding, end of year[3]	52,233	126,565	129,746
Non-cash compensation expense recognized (in thousands)	$ 694	$ 2,313	$ 2,936

(1) The weighted average prices for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense and does not represent an exercise price to be paid by the recipient, were $4.75, $44.28 and $50.09 for awards granted for the years ended December 31, 2009, 2008 and 2007, respectively

(2) The intrinsic values for phantom unit awards exercised during the years ended at December 31, 2009, 2008 and 2007 are $0.3 million, $2.0 million and $2.6 million, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2009 is $0.5 million.

At December 31, 2009, the Partnership had approximately $0.7 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIP based upon the fair value of the awards.

Partnership Unit Options. A unit option entitles a Participant to receive a common unit of the Partnership 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 the Partnership s common unit as determined by the Committee on the date of grant of the option. The Committee also shall determine how the exercise price may be paid by the Participant. The Committee will determine the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Through December 31, 2009, unit options granted under the Partnership s LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. Awards will automatically vest upon a change of control of the Partnership, as defined in the Partnership s LTIP. There are 25,000 unit options outstanding under the Partnership s LTIP at December 31, 2009 that will vest within the following twelve months. There were no Partnership unit options outstanding for the years ended December 31, 2008 and 2007.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2009	
	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period		$
Granted	100,000	6.24
Matured		
Forfeited		
Outstanding, end of period[1][2]	100,000	$ 6.24
Options exercisable, end of period		
Weighted average fair value of unit options per unit granted during the period	100,000	$ 0.14
Non-cash compensation expense recognized (in thousands)	$ 7	

(1) The weighted average remaining contractual life for outstanding options at December 31, 2009 was 9.0 years.
(2) The aggregate intrinsic value of options outstanding at December 31, 2009 was $0.4 million.

The Partnership used the Black-Scholes option pricing model to estimate the weighted average fair value of options granted. The following weighted average assumptions were used for the period indicated:

	Year Ended December 31, 2009
Expected dividend yield	11.0%
Expected stock price volatility	20.0%
Risk-free interest rate	2.2%
Expected term (in years)	6.3

Incentive Compensation Agreements

The Partnership had incentive compensation agreements which granted awards to certain key employees retained from previously consummated acquisitions. These individuals were entitled to receive common units of the Partnership upon the vesting of the awards, which was dependent upon the achievement of certain predetermined performance targets through September 30, 2007. At September 30, 2007, the predetermined performance targets were achieved and all of the awards under the incentive compensation agreements vested. Of the total common units issued under the incentive compensation agreements, 58,822 common units were issued during the year ended December 31, 2007. The ultimate number of common units issued under the incentive compensation agreements was determined principally by the financial performance of certain Partnership assets during the year ended December 31, 2008 and the market value of the Partnership s common units at December 31, 2008. The incentive compensation agreements also dictated that no individual covered under the agreements would receive an amount of common units in excess of one percent of the outstanding common units of the Partnership at the date of issuance. Common unit amounts due to any individual covered under the agreements in excess of one percent of the outstanding common units of the Partnership would have been paid in cash.

Compensation expense is recognized on a straight-line basis over the vesting period. As of December 31, 2008, the Partnership recognized in full within its consolidated statements of operations the compensation expense associated with the vesting of awards issued under these incentive compensation

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

agreements, therefore no compensation expense was recognized during the year ended December 31, 2009. The Partnership recognized a reduction of compensation expense of $36.3 million, and expense of $33.4 million for the years ended December 31, 2008 and 2007, respectively, related to the vesting of awards under these incentive compensation agreements. The non-cash compensation expense adjustments for the year ended December 31, 2008 were principally attributable to changes in the Partnership s common unit market price, which was utilized in the calculation of the non-cash compensation expense for these awards, at December 31, 2008 when compared with the common unit market price at earlier periods and adjustments based upon the achievement of actual financial performance targets through December 31, 2008. The Partnership recognized compensation expense related to these awards based upon the fair value method. During the year ended December 31, 2009, the Partnership issued 348,620 common units to the certain key employees covered under the incentive compensation agreements. No additional common units will be issued with regard to these agreements.

Employee Incentive Compensation Plan and Agreement

In June 2009, a wholly-owned subsidiary of the Partnership adopted an incentive plan (the Plan) which allows for equity-indexed cash incentive awards to employees of the Partnership (the Participants), but expressly excludes as an eligible Participant any person that, at the time of the grant, is a Named Executive Officer of the Partnership (as such term is defined under the rules of the Securities and Exchange Commission). The Plan is administered by a committee appointed by the chief executive officer of the Partnership. Under the Plan, cash bonus units may be awarded to Participants at the discretion of the committee and bonus units totaling 325,000 were awarded under the Plan in June 2009. In September 2009, the subsidiary entered into an agreement with an executive officer that granted an award of 50,000 bonus units on substantially the same terms as the bonus units available under the Plan (the bonus units issued under the Plan and under the separate agreement are, for purposes hereof, referred to as Bonus Units). A Bonus Unit entitles the employee to receive the cash equivalent of the then-fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vest ratably over a three year period from the date of grant and will automatically vest upon a change of control, death, or termination without cause, each as defined in the governing document. Vesting will terminate upon termination of employment with cause. During the year ended December 31, 2009, the Partnership granted 375,000 Bonus Units. Of the Bonus Units outstanding at December 31, 2009, 123,750 Bonus Units will vest within the following twelve months. The Partnership recognized compensation expense related to these awards based upon the fair value, which is remeasured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized $1.2 million of compensation expense within general and administrative expense on its consolidated statements of operations with respect to the vesting of these awards for the year ended December 31, 2009. At December 31, 2009, the Partnership has recognized $1.2 million within accounts payable affiliates on its consolidated balance sheet with regard to the awards, which represents their fair value at December 31, 2009.

NOTE 18 RELATED PARTY TRANSACTIONS

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of Atlas Energy. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to its employees who perform services for the Partnership based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by Atlas Energy based on the number of its employees who devote their time to activities on the Partnership s behalf.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $2.7 million, $1.5 million and $5.9 million for the years ended December 31, 2009, 2008 and 2007, respectively, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the years ended December 31, 2009, 2008 and 2007. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

NOTE 19 SEGMENT INFORMATION

The Partnership has two reportable segments. These reportable segments reflect the way the Partnership manages its operations.

The Mid-Continent segment consists of the Chaney Dell, Elk City/Sweetwater, Velma and Midkiff/Benedum operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins. Mid-Continent revenues are primarily derived from the sale of Residue Gas and NGLs and gathering of natural gas.

The Appalachia segment is comprised of natural gas transportation, gathering and processing assets located in the Appalachian Basin area of eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee and services drilling activity in the Marcellus Shale area in southwestern Pennsylvania. Effective May 31, 2009, the Appalachia operations were principally conducted through its Tennessee operations and the Partnership s 49% ownership interest in Laurel Mountain, a joint venture to which the Partnership contributed its natural gas transportation, gathering and processing assets located in northeastern Appalachia. The Partnership recognizes its ownership interest in Laurel Mountain under the equity method of accounting. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates.

The following summarizes the Partnership s reportable segment data for the periods indicated (in thousands):

	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Year Ended December 31, 2009:				
Revenue:				
Revenues third party	$ 1,779	$ 852,803	$ (83,396)	$ 771,186
Revenues affiliates	17,536			17,536
Gain on asset sale	108,947	2,493		111,440
Equity income	4,043			4,043
Total revenue and other income (loss), net	132,305	855,296	(83,396)	904,205
Costs and Expenses:				
Operating costs and expenses	6,917	652,956		659,873
General and administrative(2)			37,725	37,725
Depreciation and amortization	3,591	88,843		92,434
Goodwill and other asset impairment loss		10,325		10,325
Interest expense(2)			103,629	103,629
Total costs and expenses	10,508	752,124	141,354	903,986
Net income (loss) from continuing operations	121,797	103,172	(224,750)	219
Income from discontinued operations			62,495	62,495

Net income (loss)	$ 121,797	$ 103,172	$ (162,255)	$ 62,714

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Year Ended December 31, 2008[1]:				
Revenue:				
Revenues third party	$ 5,456	$ 1,471,516	$ (168,498)	$ 1,308,474
Revenues affiliates	43,293			43,293
Total revenue and other income (loss), net	48,749	1,471,516	(168,498)	1,351,767
Costs and expenses:				
Operating costs and expenses	13,073	1,139,951		1,153,024
General and administrative[2]			(1,838)	(1,838)
Depreciation and amortization	6,430	76,411		82,841
Goodwill and other asset impairment loss	2,304	674,556		676,860
Interest expense[2]			85,991	85,991
Gain on extinguishment of debt			(19,867)	(19,867)
Total costs and expenses	21,807	1,890,918	64,286	1,977,011
Net income (loss) from continuing operation	26,942	(419,402)	(232,784)	(625,244)
Income from discontinued operations			20,546	20,546
Net income (loss)	$ 26,942	$ (419,402)	$ (212,238)	$ (604,698)
Year Ended December 31, 2007[1]:				
Revenue:				
Revenues third party	$ 2,475	$ 805,544	$ (228,975)	$ 579,044
Revenues affiliates	33,169			33,169
Total revenue and other income (loss), net	35,644	805,544	(228,975)	612,213
Costs and expenses:				
Operating costs and expenses	7,082	610,235		617,317
General and administrative[2]			59,600	59,600
Depreciation and amortization	4,655	39,248		43,903
Interest expense[2]			62,592	62,592
Total costs and expenses	11,737	649,483	122,192	783,412
Net income (loss) from continuing operations:	23,907	156,061	(351,167)	(171,199)
Income from discontinued operations:			30,830	30,830
Net income (loss)	$ 23,907	$ 156,061	$ (320,337)	$ (140,369)

	Years Ended December 31,		
Capital Expenditures:	**2009**	**2008[1]**	**2007[1]**
Mid-Continent	$ 145,354	$ 259,221	$ 101,213

Appalachia	9,562	41,502	19,620
	$ 154,916	$ 300,723	$ 120,833

	December 31,	
Balance Sheet	**2009**	**2008(1)**
Total assets:		
Mid-Continent	$ 1,965,219	$ 1,973,723
Appalachia	170,905	114,166
Discontinued operations		255,606
Corporate other	1,839	69,701
	$ 2,137,963	$ 2,413,196

The following tables summarize the Partnership s total revenues by product or service for the periods indicated (in thousands):

	Years Ended December 31,		
Natural gas and liquids:	**2009**	**2008(1)**	**2007(1)**
Natural gas	$ 274,643	$ 559,110	$ 255,043
NGLs	428,851	688,623	434,773
Condensate	28,681	57,366	27,269
Other(2)	46,369	37,683	22,766
Total	$ 778,544	$ 1,342,782	$ 739,851

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4).

(2) The Partnership notes that derivative contracts, interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

NOTE 20 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s term loan and revolving credit facility is guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership s consolidated financial statements as of and for the years ended December 31, 2009, 2008 and 2007 include the financial statements of Chaney Dell LLC and Midkiff/Benedum, entities in which the Partnership has controlling interests (see Note 2). Under the terms of the term loan and revolving credit facility, Chaney Dell LLC and Midkiff/Benedum LLC are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership s stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership s consolidated accounts as of and for the years ended December 31, 2009, 2008 and 2007. For the purpose of the following financial information, the Partnership s investments in its subsidiaries and the guarantor subsidiaries investments in its subsidiaries are presented in accordance with the equity method of accounting (in thousands):

Balance Sheet			**December 31, 2009**		
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$	$ 1,021	$	$	$ 1,021
Accounts receivable affiliates	1,383,871			(1,383,871)	
Current portion of derivative asset		998			998
Other current assets		42,457	73,668		116,125
Total current assets	1,383,871	44,476	73,668	(1,383,871)	118,144
Property, plant and equipment, net		588,648	1,095,736		1,684,384
Notes receivable			1,852,928	(1,852,928)	
Equity investments	568,320	237,991		(806,311)	
Investment in joint venture		132,990			132,990
Intangible assets, net		18,610	149,481		168,091
Long-term derivative asset		361			361
Other assets, net	27,332	5,525	1,136		33,993
	$ 1,979,523	$ 1,028,601	$ 3,172,949	$ (4,043,110)	$ 2,137,963
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,251,468	$ 134,446	$ (1,383,871)	$ 2,043
Current portion of derivative liability		33,547			33,547
Other current liabilities	1,813	46,250	65,076		113,139
Total current liabilities	1,813	1,331,265	199,522	(1,383,871)	148,729
Long-term derivative liability		11,126			11,126
Long-term debt, less current portion	1,254,183				1,254,183
Other long-term liability		398			398

Partners Capital (deficit)	723,527	(314,188)	2,973,427	(2,659,239)	723,527
	$ 1,979,523	$ 1,028,601	$ 3,172,949	$ (4,043,110)	$ 2,137,963

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Balance Sheet	December 31, 2008[(1)]				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 7	$ 1,438	$	$	$ 1,445
Accounts receivable affiliates	1,444,812			(1,444,275)	537
Current portion of derivative asset		44,961			44,961
Current assets discontinued operations		13,441			13,441
Other current assets		37,019	73,977		110,996
Total current assets	1,444,819	96,859	73,977	(1,444,275)	171,380
Property, plant and equipment, net		681,497	1,099,514		1,781,011
Notes receivable			1,852,926	(1,852,926)	
Equity investments	677,596	194,291		(871,887)	
Intangible assets, net		21,063	172,584		193,647
Long-term assets discontinued operations		242,165			242,165
Other assets, net	23,676	1,135	182		24,993
	$ 2,146,091	$ 1,237,010	$ 3,199,183	$ (4,169,088)	$ 2,413,196
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,362,256	$ 82,019	$ (1,444,275)	$
Current portion of derivative liability		60,396			60,396
Current liabilities discontinued operations		10,572			10,572
Other current liabilities	1,822	56,105	91,299		149,226
Total current liabilities	1,822	1,489,329	173,318	(1,444,275)	220,194
Long-term derivative liability		48,159			48,159
Long-term debt, less current portion	1,493,427				1,493,427
Other long-term liability		574			574
Partners Capital (deficit)	650,842	(301,052)	3,025,865	(2,724,813)	650,842
	$ 2,146,091	$ 1,237,010	$ 3,199,183	$ (4,169,088)	$ 2,413,196

Statement of Operations	Year Ended December 31, 2009				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income (loss), net	$	$ 354,665	$ 600,966	$ (51,426)	$ 904,205
Total costs and expenses	(103,629)	(343,378)	(508,405)	51,426	(903,986)
Equity income in subsidiaries	164,801	94,193		(258,994)	
Income (loss) from continuing operations	61,172	105,480	92,561	(258,994)	219
Income from discontinued operations		62,495			62,495
Net income (loss)	$ 61,172	$ 167,975	$ 92,561	$ (258,994)	$ 62,714

Statement of Operations Year Ended December 31, 2008[(1)]

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income (loss), net	$	$ 357,311	$ 1,025,796	$ (31,340)	$ 1,351,767
Total costs and expenses	(64,976)	(534,249)	(1,409,126)	31,340	(1,977,011)
Equity income in subsidiaries	(538,183)	(381,791)		919,974	
Income (loss) from continuing operations	(603,159)	(558,729)	(383,330)	919,974	(625,244)
Income from discontinued operations		20,546			20,546
Net income (loss)	$ (603,159)	$ (538,183)	$ (383,330)	$ 919,974	$ (604,698)

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Statement of Operations	**Year Ended December 31, 2007[1]**				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Total revenue and other income (loss), net	$	$ 203,629	$ 408,584	$	$ 612,213
Total costs and expenses	(61,528)	(440,445)	(281,439)		(783,412)
Equity income in subsidiaries	(78,756)	127,230		(48,474)	
Income (loss) from continuing operations	(140,284)	(109,586)	127,145	(48,474)	(171,199)
Income from discontinued operations		30,830			30,830
Net income (loss)	$ (140,284)	$ (78,756)	$ 127,145	$ (48,474)	$ (140,369)

Statement of Cash Flows	**Year Ended December 31, 2009**				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Net cash provided by (used in) continuing operations	$ 153,969	$ (60,259)	$ 203,981	$ (260,537)	$ 37,154
Net cash provided by discontinued operations		16,935			16,935
Net cash provided by (used in) operating activities	153,969	(43,324)	203,981	(260,537)	54,089
Net cash provided by (used in) continuing investing activities	141,661	(33,064)	(60,108)	(97,960)	(49,471)
Net cash provided by discontinued investing activities		290,594			290,594
Net cash provided by (used in) investing activities	141,661	257,530	(60,108)	(97,960)	241,123
Net cash provided by (used in) financing activities	(295,637)	(214,623)	(143,873)	358,497	(295,636)
Net change in cash and cash equivalents	(7)	(417)			(424)
Cash and cash equivalents, beginning of period	7	1,438			1,445
Cash and cash equivalents, end of year	$	$ 1,021	$	$	$ 1,021

Statement of Cash Flows	**Year Ended December 31, 2008[1]**				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Net cash provided by (used in) continuing operations	$ 8,860	$ (652,406)	$ 363,886	$ 174,897	$ (104,763)
Net cash provided by discontinued operations		45,569			45,569
Net cash provided by (used in) operating activities	8,860	(606,837)	363,886	174,897	(59,194)
Net cash provided by (used in) continuing investing activities	(350,102)	575,230	(53,030)	(439,831)	(267,733)
Net cash used in discontinued investing activities		(25,211)			(25,211)
Net cash provided by (used in) investing activities	(350,102)	550,019	(53,030)	(439,831)	(292,944)
Net cash provided by (used in) financing activities	341,242	63,971	(328,905)	264,934	341,242

Net change in cash and cash equivalents		7,153	(18,049)		(10,896)
Cash and cash equivalents, beginning of year	7	(5,715)	18,049		12,341
Cash and cash equivalents, end of year	$ 7	$ 1,438	$	$	$ 1,445

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Statement of Cash Flows	Year Ended December 31, 2007[1]				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash provided by (used in) continuing operations	$ (2,061,375)	$ 119,500	$ 77,280	$ 1,926,125	$ 61,530
Net cash provided by discontinued operations		38,914			38,914
Net cash provided by (used in) operating activities	(2,061,375)	158,414	77,280	1,926,125	100,444
Net cash provided by (used in) continuing investing activities	126,316	(286,289)	(1,899,378)	53,587	(2,005,764)
Net cash used in discontinued investing activities		(18,879)			(18,879)
Net cash provided by (used in) investing activities	126,316	(305,168)	(1,899,378)	53,587	(2,024,643)
Net cash provided by financing activities	1,935,059	133,565	1,840,147	(1,979,712)	1,935,059
Net change in cash and cash equivalents		(7,189)	18,049		10,860
Cash and cash equivalents, beginning of year	7	1,474			1,481
Cash and cash equivalents, end of year	$ 7	$ (5,715)	$ 18,049	$	$ 12,341

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4).

NOTE 21 QUARTERLY FINANCIAL DATA (Unaudited)

	Fourth Quarter[1]	Third Quarter[2]	Second Quarter[3]	First Quarter[4]
	(in thousands, except per unit data)			
Year ended December 31, 2009:				
Revenue and other income (loss), net	$ 241,127	$ 206,533	$ 282,304	$ 174,241
Costs and expenses	276,252	218,856	202,525	206,353
Income (loss) from continuing operations	(35,125)	(12,323)	79,779	(32,112)
Income (loss) from discontinued operations			53,619	8,876
Net income (loss)	$ (35,125)	$ (12,323)	$ 133,398	$ (23,236)
Net income (loss) attributable to common limited partners per unit basic:				
Income (loss) from continuing operations attributable to common limited partners	$ (0.70)	$ (0.26)	$ 1.63	$ (0.71)
Income (loss) from discontinued operations attributable to common limited partners			1.10	0.19
Net income (loss) attributable to common limited partners	$ (0.70)	$ (0.26)	$ 2.73	$ (0.52)
Net income (loss) attributable to common limited partners per unit diluted:				

Income (loss) from continuing operations attributable to common limited partners [5]	$	(0.70)	$	(0.26)	$	1.63	$	(0.71)
Income (loss) from discontinued operations attributable to common limited partners [5]						1.10		0.19
Net income (loss) attributable to common limited partners [5]	$	(0.70)	$	(0.26)	$	2.73	$	(0.52)

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Net loss includes an $11.7 million non-cash derivative loss and a $10.3 million non-cash impairment charge for goodwill and other assets.
(2) Net loss includes a $7.5 million non-cash derivative gain.
(3) Net income includes a $2.5 million non-cash derivative loss and a $79.8 million non-cash gain of the total $111.4 million gain on the sale of assets.
(4) Net loss includes a $44.0 million non-cash derivative loss and a $5.0 million cash derivative expense from the early termination of certain derivative instruments.
(5) For the first quarter of the year ended December 31, 2009, potential common limited partner units issuable upon conversion of the Partnership s Class A and Class B cumulative convertible preferred limited partner units were excluded from the computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

	Fourth Quarter[2]	Third Quarter[3]	Second Quarter[4]	First Quarter[5]
	(in thousands, except per unit data)			
Year ended December 31, 2008[1]:				
Revenue and other income (loss), net	$ 362,927	$ 568,658	$ 133,167	$ 287,015
Costs and expenses	849,017	374,032	416,971	336,991
Income (loss) from continuing operations	(486,090)	194,626	(283,804)	(49,976)
Income (loss) from discontinued operations	(483)	6,538	8,245	6,246
Net income (loss)	(486,573)	201,164	(275,559)	(43,730)
Net income (loss) attributable to common limited partners per unit basic:				
Income (loss) from continuing operations attributable to common limited partners	$ (9.69)	$ 3.89	$ (7.34)	$ (1.50)
Income (loss) from discontinued operations attributable to common limited partners	$ (0.01)	$ 0.14	$ 0.21	$ 0.16
Net income (loss) attributable to common limited partners	$ (9.70)	$ 4.03	$ (7.13)	$ (1.34)
Net income (loss) attributable to common limited partners per unit diluted:				
Income (loss) from continuing operations attributable to common limited partners [5]	$ (9.69)	$ 3.79	$ (7.34)	$ (1.50)
Income (loss) from discontinued operations attributable to common limited partners [5]	$ (0.01)	$ 0.14	$ 0.21	$ 0.16
Net income (loss) attributable to common limited partners [5]	$ (9.70)	$ 3.93	$ (7.13)	$ (1.34)

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4).

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Net loss includes a $690.5 million non-cash impairment charge for goodwill and other assets, a $151.8 million non-cash derivative gain, and a $19.9 million gain from the Partnership s repurchase of approximately $60.0 million in face amount of its Senior Notes for an aggregate purchase price of approximately $40.1 million.

(3) Net income includes a $222.0 million non-cash derivative gain and a $71.5 million cash derivative expense from the early termination of certain derivative instruments.

(4) Net loss includes a $181.1 million non-cash derivative loss and a $116.1 million cash derivative expense from the early termination of certain derivative instruments.

(5) Net loss includes a $76.9 million non-cash derivative loss.

(6) For the fourth, second and first quarters of the year ended December 31, 2008, potential common limited partner units issuable upon conversion of the Partnership s Class A and Class B cumulative convertible preferred limited partner units were excluded from the computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

NOTE 22 SUBSEQUENT EVENTS

On January 7, 2010, the Partnership executed amendments to warrants to purchase 2,689,765 of the Partnership s common units. The warrants were originally issued along with the Partnership s common units in connection with a private placement to institutional investors that closed on August 20, 2009. The common units and warrants were issued and sold in a transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million to the Partnership.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

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

Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2009, our disclosure controls and procedures were effective at the reasonable assurance level.

Management s Report on Internal Control over Financial Reporting

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

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

Based on our evaluation under the COSO framework, management concluded that internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2009.

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Grant Thornton LLP, an independent registered public accounting firm and auditors of our consolidated financial statements, has issued its report on the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2009, which is included herein.

There have been no changes in our internal control over financial reporting during the fourth quarter of 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited Atlas Pipeline Partners, L.P. s (a Delaware limited partnership) internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Atlas Pipeline Partners, L.P. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Atlas Pipeline Partners, L.P. s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Atlas Pipeline Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atlas Pipeline Partners, L.P. and subsidiaries as of December 31, 2009 and 2008 and the related consolidated statements of operations, comprehensive income (loss), partners capital and cash flows for each of the three years in the period ended December 31, 2009, and our report dated March 5, 2010 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

March 5, 2010

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ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

As set forth in our Partnership Governance Guidelines and in accordance with NYSE listing standards, the non-management members of the managing board 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 is to promote open and candid discussion among the non-management board members. Interested parties wishing to communicate directly with the non-management members may contact the chairman of the audit committee, Martin Rudolph, at P.O. Box 769, Ardmore, Pennsylvania 19003.

The independent board members comprise all of the members of both 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. Any matters approved by the conflicts committee are conclusively judged to be fair and reasonable to us, approved by all our partners and not a breach by our General Partner or its managing board of any duties they may owe us or the unitholders. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls.

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

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, Atlas Energy personnel manage and operate our business. Some of our officers of our General Partner may spend a substantial amount of time managing the business and affairs of Atlas Energy and its affiliates and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

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Managing Board Members and Executive Officers of Our General Partner

The following table sets forth information with respect to the executive officers and managing board members of our General Partner:

Name	Age	Position with the General Partner	Year in which service began
Eugene N. Dubay	61	Chief Executive Officer, President and Managing Board Member	2008
Eric T. Kalamaras	36	Chief Financial Officer	2009
Edward E. Cohen	71	Chairman of the Managing Board	1999
Jonathan Z. Cohen	39	Vice Chairman of the Managing Board	1999
Gerald R. Shrader	50	Chief Legal Officer and Secretary	2009
Robert W. Karlovich, III	32	Chief Accounting Officer	2009
Tony C. Banks	55	Managing Board Member	1999
Curtis D. Clifford	67	Managing Board Member	2004
Martin Rudolph	63	Managing Board Member	2005
Michael L. Staines	60	Managing Board Member	1999

Eugene N. Dubay has been President and Chief Executive Officer of our General Partner since January 2009. Mr. Dubay has served as a member of the managing board of our General Partner since October 2008, where he served as an independent member until his appointment as President and Chief Executive Officer. Mr. Dubay has been the Chief Executive Officer, President and a director of Atlas Pipeline Holdings since February 2009. 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 (a successor to 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. Throughout his career, Mr. Dubay has held positions of increasing responsibility in the energy industry. In these positions, Mr. Dubay has been responsible for developing and implementing strategic plans including, as applicable, regulatory strategies. This long-range approach is important to the Board s development of our strategic plans. This combined experience and approach served as the basis for Mr. Dubay s appointment as a director.

Eric T. Kalamaras has been Chief Financial Officer of our General Partner since September 2009. Mr. Kalamaras has been the Chief Financial Officer of Atlas Pipeline Holdings since September 2009. From 2003 to 2009, Mr. Kalamaras was Director of Energy Leveraged Finance & High Yield for Wells Fargo Securities, LLC (formerly Wachovia Securities, LLC), where he focused on equity and debt capital funding in public and private natural gas master limited partnerships. From 1999 to 2003, Mr. Kalamaras was an analyst with Banc of America Securities.

Edward E. Cohen has been the Chairman of the managing board of our General Partner since its formation in 1999. Mr. Cohen was the Chief Executive Officer of our General Partner since its formation in 1999 through January 2009. Mr. Cohen has been the Chairman of the Board of Atlas Holdings GP, the General Partner of Atlas Pipeline Holdings, since its formation in January 2006. Mr. Cohen served as Chief Executive Officer of Atlas Pipeline Holdings from its formation until February 2009. Mr. Cohen also has been the Chairman of the Board and Chief Executive Officer of Atlas Energy (formerly known as Atlas America, Inc.) since its organization in 2000 and also served as its President from 2000 to October 2009 when Atlas Energy Resources became its wholly-owned subsidiary following its merger transaction. Mr. Cohen has been the Chairman of the Board and Chief Executive Officer of Atlas Energy Resources and its manager, Atlas Energy Management, Inc.; since their formation in June 2006. In addition, Mr. Cohen has been Chairman of the Board of Directors of Resource America, Inc. (a publicly-traded

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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.

Jonathan Z. Cohen has been Vice Chairman of the managing board of our General Partner since our formation in 1999. Mr. Cohen has been the Vice Chairman of the Board of Atlas Holdings GP since its formation in January 2006. Mr. Cohen also has been the Vice Chairman of the Board of Atlas Energy (formerly known as Atlas America, Inc.) since its organization in 2000. Mr. Cohen has been Vice Chairman of the Board of Atlas Energy Resources and Atlas Energy Management since their formation in June 2006. 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 our board to assist with our growth and development.

Gerald R. Shrader has been the Chief Legal Officer and Secretary of our General Partner since October 2009. Mr. Shrader has been the Chief Legal Officer and Secretary of Atlas Holdings GP since October 2009 and has also been the General Counsel and a Senior Vice President of Atlas Pipeline Mid-Continent, LLC since August 2007. From January 2006 through July 2007, Mr. Shrader was the Assistant General Counsel of CMS Enterprises Company, a subsidiary of CMS Energy Corporation, a publicly-traded energy company. From November 2005 through January 2006, he was the General Counsel of Atlas Pipeline Mid-Continent, LLC. From July 2003 through November 2005, Mr. Shrader was self-employed, primarily providing consulting services to CMS Enterprises Company.

Robert W. Karlovich, III has been the Chief Accounting Officer of our General Partner since November 2009. Mr. Karlovich has been the Chief Accounting Officer of Atlas Holdings GP since November 2009. Before that, he was the Controller of Atlas Pipeline Mid-Continent, LLC, our wholly-owned subsidiary, since September 2006. Mr. Karlovich was the Controller for Syntroleum Corporation, a publicly-traded energy company, from April 2005 until September 2006, and Accounting Manager from February 2004. Mr. Karlovich also worked as a public accountant with Arthur Andersen LLP and Grant Thornton LLP where he served numerous public clients and energy companies. Mr. Karlovich is a certified public accountant.

Tony C. Banks has been Vice President of Product and Market Development for FirstEnergy Solutions Corp., a subsidiary of FirstEnergy Corporation, a public utility, since October 2009. From March 2007 to October 2009, Mr. Banks served as Vice President of Business Development, Performance & Management for FirstEnergy Corporation. From December 2005 to February 2007, Mr. Banks was Vice President of Business Development for FirstEnergy Corporation. Mr. Banks first joined FirstEnergy Solutions, Corp., in August 2004 as Director of Marketing and in August 2005 became Vice President of Sales & Marketing. Before joining FirstEnergy, Mr. Banks was a consultant to utilities, energy service companies and energy technology firms. From 2000 through 2002, Mr. Banks was President of RAI Ventures, Inc. and Chairman of the Board of Optiron Corporation, an energy technology subsidiary of Atlas Energy. In addition, Mr. Banks served as President of our General Partner during 2000. He was

Chief Executive Officer and President of Atlas Energy from 1998 through 2000 and served on the board of directors of TRM Corporation, a provider of ATM services, from October 2006 to April 2008. In Mr. Banks role at Atlas Energy, he gained experience in natural gas exploration and production. Prior to that time, Mr. Banks was engaged primarily in the natural gas distribution business. Currently, Mr. Banks is engaged primarily with electricity generation, pricing and marketing including involvement with renewable energy standards and compliance with certain emission requirements for electricity generators. Among the reasons for Mr. Banks appointment as a director, Mr. Banks supplements the knowledge of our other board members with respect to natural gas production and the markets for natural gas.

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. Since January 2001, he has worked for UtiliTech, Inc., utility and telecommunications specialists in West Lawn, PA, where he advises and assists commercial and industrial gas consumers nationwide with procurement activities and utility rate options. He is also President of Amity Manor, Inc. which he founded in 1988 to develop housing for low-income elderly using tax credit financing. Mr. Clifford is a Life Member of the American Society of Civil Engineers and is a registered professional engineer in Pennsylvania. Mr. Clifford has 43 years experience in the natural gas industry, from exploration, production and gathering to procurement, marketing and utility rates. Among the reasons for his appointment as a director, Mr. Clifford s experience provides valuable strategic insight in gauging the markets for our services and products.

Martin Rudolph has been the Trustee of the AHP Settlement Trust, a billion dollar trust established to process litigation claims, since 2005. Before that, Mr. Rudolph was a director of tax planning, research and compliance for RSM McGladrey, Inc., a business services firm from 2001 to 2005. From 1990 to 2001, he was the Managing Partner of Rudolph, Palitz LLC, which merged with McGladrey & Pullen LLP, a national accounting firm. At McGladrey & Pullen LLP, Mr. Rudolph was the Managing Partner of the Philadelphia economic unit. In that position, he oversaw all of the professional services rendered by the Firm, which included the audit of public and privately-held companies. Mr. Rudolph brings a strong accounting background to our board and serves as the chair of our audit committee. Among the reasons for his appointment as a director, Mr. Rudolph s 35 years experience as an independent certified public accountant has been critical in developing our internal audit regime and is needed to further guide that program.

Michael L. Staines has been the President of Pine Tree Energy Partners, LLC, an energy consulting firm since October 2009. From 2000 to January 2009, Mr. Staines was our President and Chief Operating Officer. Mr. Staines was an Executive Vice President of Atlas Energy from its formation in 2000 until July 2009. Mr. Staines was Senior Vice President of Resource America from 1989 to 2004 and served as a director from 1989 through 2000 and Secretary from 1989 through 1998. Mr. Staines is a member of the Independent Oil and Gas Association of Pennsylvania and the Independent Petroleum Association of America. Mr. Staines brings extensive knowledge regarding oil and gas production in Pennsylvania, which complements our development and participation in Laurel Mountain. In addition, Mr. Staines has historical knowledge of our company and operations and was involved in our strategic development. This knowledge and experience served as a basis for Mr. Staines appointment as a director. With this background, Mr. Staines advice can help guide our continued development.

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

Edward E. Cohen serves as the chairman of the managing board of our General Partner and Eugene N. Dubay serves as the chief executive officer of our General Partner. The managing board of

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our General Partner believes that oversight of management is an important component of an effective managing board. The managing board members believe that the most effective leadership structure at the present time is for separation of the chairman of the managing board from the chief executive officer position. The managing board members believe that because the chief executive officer is ultimately responsible for our day-to-day operations and for executing our strategy, we are best served to have a separate role of chairman of the managing board of our General Partner as it allows for proper oversight, guidance and accountability. The chief executive officer contacts the chairman of the managing board on a regular basis and provides status updates of operations during these discussions.

We administer our risk oversight function through our audit committee as well as through the managing board of our General Partner as a whole. Our audit committee was appointed to assist our managing board in fulfilling its oversight duties. Our audit committee is empowered to appoint and oversee our independent auditors, monitor the integrity of our financial reporting processes and systems of internal controls and provide an avenue of communication among our independent auditors, management, our internal auditing department and our managing board of our General Partner. Additionally, individuals who oversee risk management in liquidity and credit areas, and environmental, litigation and other operational areas provide reports to the managing board of our General Partner during regular board meetings.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers and managing board members of our General Partner and persons who beneficially own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the Securities and Exchange Commission and to furnish us with copies of all such reports. Based solely upon our review of reports received by us, or representations from certain reporting persons that no filings were required for those persons, we believe that all of the officers and managing board members of our General Partner and persons who beneficially owned more than 10% of our common units complied with all applicable filing requirements during fiscal year 2009, except that Mr. Dubay inadvertently filed one Form 4 late.

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 determined by our General Partner in its sole discretion. 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. We reimbursed our General Partner and its affiliates $2.7 million for compensation and benefits during 2009.

Information Concerning the Audit Committee

Our managing board has a standing audit committee. All of the members of the audit committee are independent directors as defined by NYSE rules. The members of the audit committee are Mr. Rudolph, Mr. Clifford, and Mr. Banks, with Mr. Rudolph acting as the chairman. Our managing board has determined that Mr. Rudolph is an audit committee financial expert, as defined by SEC rules. The audit committee reviews the scope and effectiveness of audits by the independent accountants, is responsible for the engagement of independent accountants and reviews the adequacy of our internal controls.

Compensation Committee Interlocks and Insider Participation

Neither we nor the managing board of our General Partner has a compensation committee. Compensation of the personnel of Atlas Energy and its affiliates who provide us with services is set by Atlas Energy and such affiliates. The independent members of the managing board of our General Partner, however, do review the allocation of the salaries of such personnel for purposes of reimbursement, discussed in Reimbursement of Expenses of our General Partner and Its Affiliates, above and in Item 11, Executive Compensation.

Mr. Banks was the Chairman of the Board of Optiron Corporation, which was a subsidiary of Atlas Energy until 2002. At our October 2006 managing board meeting, the managing board determined Mr. Banks to be an independent board member pursuant to NYSE listing standards and Rule 10A-3(b) promulgated under the Securities Exchange Act of 1934. None of the other independent managing board members is an employee or former employee of ours or of our General Partner. No executive officer of our General Partner is a director or executive officer of any entity in which an independent managing board member is a director or executive officer.

Code of Business Conduct and Ethics, Partnership Governance Guidelines and Audit Committee Charter

We have adopted a code of business conduct and ethics that applies to the principal executive officer, principal financial officer and principal accounting officer of our General Partner, as well as to persons performing services for us generally. We have also adopted Partnership Governance Guidelines and a charter for the audit committee. We will make a printed copy of our code of ethics, our Partnership Governance Guidelines and our audit committee charter available to any unitholder who so requests. Requests for print copies may be directed to us as follows: Atlas Pipeline Partners, L.P., Westpointe Corporate Center, 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108, Attention: Secretary. Each of the code of business conduct and ethics, the Partnership Governance Guidelines and the audit committee charter are posted, and any waivers we grant to our business conduct and ethics will be posted, on our website at www.atlaspipelinepartners.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We are required to provide information regarding the compensation program in place as of December 31, 2009, for our General Partner s CEO, CFO and the three other most highly-compensated executive officers. In this report, we refer to our General Partner s CEO, CFO and the other three most highly-compensated executive officers as our named executive officers or NEOs. This section should be read in conjunction with the detailed tables and narrative descriptions below.

Except for the Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan (the APLMC Plan), we do not directly compensate our named executive officers. Rather, Atlas Energy allocates the compensation of our executive officers between activities on behalf of us and activities on behalf of itself and its affiliates based upon an estimate of the time spent by such persons on activities for us and for Atlas Energy and its affiliates. Because Messrs. Dubay, Kalamaras, Shrader and Karlovich devote all of their time to us and AHD, all of their compensation costs are allocated to us. We reimburse Atlas Energy for the compensation allocated to us. Because Atlas Energy employs our NEOs, its compensation committee, comprised solely of independent directors, has been responsible for formulating and presenting recommendations to its board of directors with respect to the compensation of our NEOs. The Atlas Energy compensation committee has also been responsible for administering our employee benefit plans, including our incentive plans.

Compensation Objectives

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

Compensation Methodology

The Atlas Energy compensation committee generally makes recommendations to the Atlas Energy board on compensation amounts shortly after the close of its (and our) fiscal year. In the case of base salaries, it recommends the amounts to be paid for the new fiscal year. In the case of annual bonus and long-term incentive compensation, the committee recommends the amount of awards based on the then concluded fiscal year. Atlas Energy and we typically pay cash awards and issue equity awards in February, although the Atlas Energy compensation committee has the discretion to recommend salary adjustments and the issuance of equity awards at other times during the fiscal year. In addition, some of our NEOs who also perform services for Atlas Energy and its subsidiaries may receive stock-based awards from Atlas Energy and these subsidiaries, each of which have delegated compensation decisions to the Atlas Energy compensation committee because they, like us, do not have their own employees.

Each year, our Chairman, who also serves as Atlas Energy s Chief Executive Officer and Chairman, provides the Atlas Energy compensation committee with key elements of Atlas Energy s, our and our NEOs performance during the year. Our Chairman makes recommendations to the compensation committee regarding the salary, bonus, and incentive compensation component of each NEO s total compensation. Our Chairman, at the compensation committee s request, may attend committee meetings; however, his role during the meetings is to provide insight into Atlas Energy s and our company s performance, as well as the performance of other comparable companies in the same industry.

Compensation Consultant

The Atlas Energy compensation committee has retained Mercer (US) Inc. on an annual basis to provide information, analyses, and advice regarding executive compensation. In June 2009, the compensation committee engaged Mercer to conduct a competitive review of its then current NEO compensation program. This review included three of our NEOs: Messrs. E. Cohen, J. Cohen and M. Jones. Mercer provided a proxy analysis based on a peer group of 14 energy companies, which we refer to as the full peer group, against which Atlas Energy competes for executive talent, land and mineral rights, oil and gas services, pipeline and takeaway capacity, and/ or water disposal capacity. The peer group consists of: Anadarko Petroleum Corporation, Chesapeake Energy Corporation, Cabot Oil & Gas Corporation, CONSOL Energy Inc., EQT Corporation, Exco Resources, Inc., Linn Energy, LLC, MarkWest Energy Partners, L.P., Quicksilver Resources Inc., Pioneer Natural Resources Company, Range Resources Corporation, Southwestern Energy Company, The Williams Companies, Inc., and XTO Energy Inc. In our business, we compete against some of the members of the peer group for takeaway capacity, processing services and/or water disposal capacity.

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Mercer also analyzed a 10-company subset of the full peer group, which we refer to as the size-adjusted peer group, that included companies 2008 revenues of between $750 million to $3 billion, that is, approximately one-half to twice Atlas Energy s revenues. The size-adjusted peer group excluded Anadarko Petroleum, Chesapeake Energy, Williams, and XTO Energy. In addition, Mercer provided a survey analysis of competitive data gathered from published surveys.

The compensation committee does not set a specific percentile range for NEO compensation amounts. Rather, it uses the comparative information as part of the total mix of information it considers.

In addition to the competitive analysis of the NEO compensation program, at the compensation committee s direction, Mercer provided the following services for the committee during fiscal 2009:

- provided advice with respect to Atlas Energy s new long-term incentive plan;
- advised the committee with respect to awards for 2009 under Atlas Energy s Senior Executive Plan, discussed below, and established performance measures and performance targets for 2010; and
- provided advice on the employment agreement for Mr. Jones.

In the course of conducting its activities for fiscal 2009, Mercer attended five meetings of the compensation committee and presented its findings and recommendations for discussion.

The compensation committee has established procedures that it considers adequate to ensure that Mercer s advice remains objective and is not unduly influenced by Atlas Energy s management. These procedures include: a direct reporting relationship of the Mercer consultant to the chairman of the compensation committee; provisions in the engagement letter with Mercer specifying the information, data, and recommendations that can and cannot be shared with management; an annual update to the compensation committee on Mercer s financial relationship with Atlas Energy, including a summary of the work performed for Atlas Energy during the preceding 12 months; and written assurances from Mercer that, within the Mercer organization, the Mercer consultant who performs services for the compensation committee has a reporting relationship and compensation determined separately from Mercer s other lines of business and from its other work for Atlas Energy. In fact, Mercer did not perform non-executive compensation consulting services for Atlas Energy during the last fiscal year or during any other year. With the consent of the compensation committee chair, Mercer may contact Atlas Energy s executive officers for information necessary to fulfill its assignment and may make reports and presentations to and on behalf of the compensation committee that the executive officers also receive.

In making its compensation decisions, the compensation committee meets in executive session, without management, both with and without Mercer. Ultimately, the decisions regarding executive compensation are made by the compensation committee after extensive discussion regarding appropriate compensation and may reflect factors and considerations other than the information and advice provided by Mercer and our Chairman. The compensation committee s decisions are then submitted to the Board.

Elements of our Compensation Program

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

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Base Salary

Base salary is intended to provide fixed compensation to the NEOs for their performance of core duties that contributed to the success of Atlas Energy and us. Base salaries are not intended to compensate individuals for 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 one 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 Atlas Energy compensation committee may recommend awards of performance-based bonuses and discretionary bonuses.

Performance-Based Bonuses The Atlas Energy Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, provides awards for the achievement of predetermined, objective performance measures over a specified 12-month performance period, generally Atlas Energy s fiscal year. Awards under the Senior Executive Plan may be paid in cash or in shares of Atlas Energy s common stock under its stock incentive plan. The Senior Executive Plan is designed to permit Atlas Energy to qualify for an exemption from the $1,000,000 deduction limit under Section 162(m) of the Internal Revenue Code for compensation paid to the NEOs. Notwithstanding the existence of the Senior Executive Plan, the Atlas Energy compensation committee believes that the interests of Atlas Energy s stockholders and our unitholders are best served by not restricting its discretion and flexibility in crafting compensation, even if the compensation amounts result in non-deductible compensation expense. Therefore, the committee reserves the right to approve compensation that is not fully deductible.

In March 2009, the compensation committee approved 2009 target bonus awards to be paid from a bonus pool. The bonus pool is equal to 18.3% of Atlas Energy s adjusted distributable cash flow unless the adjusted distributable cash flow includes any capital transaction gains in excess of $50 million, in which case only 10% of that excess will be included in the bonus pool. If the adjusted distributable cash flow does not equal at least 75% of the average adjusted distributable cash flow for the previous 3 years, no bonuses will be paid. Adjusted distributable cash flow means the sum of (i) cash available for distribution to Atlas Energy by any of its subsidiaries (regardless of whether such cash is actually distributed), plus (ii) interest income during the year, plus (iii) to the extent not otherwise included in adjusted distributable cash flow, any realized gain on the sale of securities, including securities of a subsidiary, less (iv) Atlas Energy s stand-alone general and administrative expenses for the year excluding any bonus expense (other than non-cash bonus compensation included in general and administrative expenses), and less (v) to the extent not otherwise included in adjusted 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 is not intended to be included and, accordingly, if adjusted distributable cash flow includes proceeds from the sale of all or substantially all of the assets of a subsidiary, the amount of such proceeds to be included in adjusted distributable cash flow will be reduced by its basis in the subsidiary. The maximum award payable, expressed as a percentage of Atlas Energy s estimated 2009 adjusted distributable cash flow, for its NEO participants was as follows: Edward E. Cohen, 6.14%; Jonathan Z. Cohen, 4.37% and Matthew A. Jones, 3.46%. Pursuant to the terms of the Senior Executive Plan, the compensation committee has the discretion to recommend reductions, but not increases, in awards under the plan. As set forth below, actual awards for 2009 were substantially less than the maximum award permitted under the plan. In February 2010, the compensation committee approved target bonus awards identical to the 2009 target bonus awards.

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Discretionary Bonuses Discretionary bonuses may be awarded to recognize individual and group performance. Mr. Shrader received a cash bonus of $50,000 in recognition of his performance in connection with the disposition of our NOARK assets.

Long-Term Incentives

We believe that our long-term success depends upon aligning our executives and unitholders interests. To support this objective, Atlas Energy provides our executives with various means to become significant equity holders, including awards under our Long-Term Incentive Plan, which we refer to as our Plan. Our NEOs are also eligible to receive awards under the Atlas Energy Stock Incentive Plans, which we refer to as the Atlas Plans, and the Atlas Pipeline Holdings Long-Term Incentive Plan, which we refer to as the AHD Plan, as appropriate.

Grants under our Plan: The Atlas Energy compensation committee may recommend grants of equity awards in the form of options and/or phantom units. Other than the unit options that were granted to Mr. Dubay in connection with the execution of his employment agreement, only phantom units have been granted under our Plan through December 31, 2009. The unit options and phantom units vest over four years.

Grants under Other Plans: As described above, our NEOs who perform services for us and one or more of Atlas Energy s subsidiaries may receive stock-based awards under the Atlas Plan or the AHD Plan.

Supplemental Benefits, Deferred Compensation and Perquisites

We do not provide supplemental benefits for executives and perquisites are discouraged. Atlas Energy does provide a Supplemental Executive Retirement Plan for Messrs. E. Cohen and J. Cohen pursuant to their employment agreements, but none of those benefits or related costs are allocated to us. None of our NEOs have deferred any portion of their compensation.

Employment Agreements

Generally, Atlas Energy does not favor employment agreements unless they are required to attract or to retain executives to the organization. It entered into employment agreements Messrs. E. Cohen, J. Cohen, E. Dubay, M. Jones and E. Kalamaras. See Employment Agreements and Potential Payments Upon Termination or Change of Control. The Atlas Energy compensation committee takes termination compensation payable under these agreements into account in determining annual compensation awards, but ultimately its focus is on recognizing each individual s contribution to Atlas Energy s and our performance during the year.

Determination of 2009 Compensation Amounts

As described above, after the end of Atlas Energy s 2009 fiscal year, the Atlas Energy compensation committee set the base salaries of our NEOs for the 2010 fiscal year and recommended incentive awards based on the prior year s performance. In carrying out its function, the Atlas Energy compensation committee acted in consultation with Mercer.

In determining the actual amounts to be paid to the NEOs, the Atlas Energy compensation committee considered both individual and company performance. Our CEO makes recommendations of award amounts based upon the NEOs individual performances as well as the performance of Atlas Energy s subsidiaries for which each NEO provides service; however, the Atlas Energy compensation committee has the discretion to approve, reject, or modify the recommendations. The Atlas Energy compensation committee noted that our management team had repositioned us through renegotiation of bank arrangements, strengthened hedging, increased volumes, effectuated a joint venture with Williams, and restructured the Mid-Continent division. In addition, the compensation committee reviewed the calculations of Atlas Energy s adjusted distributable cash flow and determined that 2009 adjusted distributable cash flow exceeded the pre-determined minimum threshold of 75% of the average adjusted distributable cash flow for the previous three years by more than 50%.

Base Salary. Following a review of the analysis conducted by Mercer in June 2009 of the Atlas Energy NEOs compensation, the compensation committee determined to increase base salaries by $100,000 effective July 1, 2009 for each of its NEOs, including those of Messrs. E. Cohen, J. Cohen and M. Jones, and for Mr. Dubay. In light of these interim increases, the compensation committee determined at the end of the 2009 fiscal year that the adjusted base salaries for those individuals were appropriate for the 2010 fiscal year. In addition, the compensation committee set 2010 salaries for our other NEOs as follows: Mr. Kalamaras-$275,000 Mr. Karlovich-$180,000; and Mr. Shrader-$275,000. These amounts represent a 10% increase from the 2009 base salaries for each of Messrs. Kalamaras and Shrader. Mr. Karlovich s base salary was increased by 22% as a result of an internal company survey which indicated that his previous salary was not commensurate with his position and responsibilities.

Annual Incentives.

Performance-Based Bonuses. As described above, Atlas Energy substantially outperformed the incentive goals that had been set under the Senior Executive Plan. Based upon this performance, the compensation committee recommended that Atlas Energy award cash incentive bonuses to its NEOs as follows: Edward E. Cohen, $2,500,000; Jonathan Z. Cohen, $2,000,000; and Matthew A. Jones, $800,000. The compensation committee also recommended that each of the NEOs receive an amount of Atlas Energy restricted stock units equivalent to their cash bonuses. The restricted stock units will vest 25% per annum. The aggregate annual incentive awards were less than the maximum amount payable to each of the NEOs pursuant to the predetermined percentages established under the Senior Executive Plan, which were as follows: Edward E. Cohen, $8,639,000; Jonathan Z. Cohen, $6,148,000; and Matthew A. Jones.

Discretionary Bonuses. Messrs. Dubay, Kalamaras, Karlovich and Shrader are not participants in the Senior Executive Plan. Therefore, the compensation committee awarded them discretionary bonuses as follows: Mr. Dubay-$500,000 in cash and $500,000 in Atlas Energy restricted stock units that vest over four years, Mr. Kalamaras-$72,917, Mr. Karlovich-$73,308; and Mr. Shrader-$250,000. Because the Atlas Energy restricted stock unit award was made after our fiscal year end, it is not included, under new SEC rules, in our Summary Compensation Table for 2009, but will be included in our table for 2010.

Long-Term Incentives. In order to retain management and in recognition of company and individual accomplishments in 2009 as set forth above, the compensation committee determined to award Atlas Energy stock options to Messrs. Dubay and Kalamaras which vest 25% per year on the anniversary of the grant date as follows: Mr. Dubay-70,000 and Mr. Kalamaras-19,000. Because the Atlas Energy stock option awards were made after our fiscal year end, it is not included, under new SEC rules, in our Summary Compensation Table for 2009, but will be included in our table for 2010.

Dubay Employment Agreement. Pursuant to the terms of his employment agreement in January 2009, Mr. Dubay was granted the following awards:

Options to purchase 100,000 shares of Atlas Energy s common stock, which vest 25% per year on each anniversary of the effective date of the agreement;

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Options to purchase 100,000 of our common units, which vest 25% per year on each anniversary of the effective date of the agreement; and

Options to purchase 100,000 AHD common units, which vest 25% on the third anniversary, and 75% on the fourth anniversary, of the effective date of the agreement.

APLMC Plan Awards. The APLMC Plan specifically prohibits awards to anyone who is a named executive officer at the time of the grant. Messrs. Shrader and Karlovich received awards under the APLMC Plan, but were granted those awards prior to becoming named executive officers. No additional grants to our named executive officers can be made under the APLMC Plan. In addition, upon execution of his employment agreement in September 2009, Mr. Kalamaras was awarded 50,000 bonus units.

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) [1]	Option Awards ($) [2]	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)	Total ($)
Eugene N. Dubay, Chief Executive Officer and President[4]	2009	$ 438,847	$ 500,000	$	$ 564,000	$	$ 555,805[3]	$ 2,058,652
Eric T. Kalamaras,[5] Chief Financial Officer	2009	157,000	152,917[6]	66,620[7]				376,537
Edward E. Cohen,	2009	147,577				375,000	12,600[9]	535,177
Chairman of the Board and	2008	135,000			3,507,000		257,938	3,899,938
Former Chief Executive Officer and President[8]	2007	405,000		4,612,160	1,205,000	2,250,000	253,212	8,725,372
Matthew A. Jones,	2009	126,270				280,000	3,950[10]	410,220
Former Chief Financial Officer	2008	135,000			1,402,800		67,713	1,605,513
of Atlas Pipeline GP	2007	135,000		461,216	120,500	900,000	75,062	1,691,778
Jonathan Z. Cohen,	2009	101,539				300,000	7,863[11]	409,402
Vice Chairman of Atlas Pipeline	2008	90,000			2,805,600		113,488	3,009,088
GP	2007	215,217		2,306,080	482,000	1,434,783	153,906	4,591,986
Gerald R. Shrader, Chief Legal Officer	2009	224,616	300,000[12]	96,000[7]				620,616
Robert W. Karlovich, III Chief Accounting Officer	2009	152,255	73,308	48,000[7]				273,563

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(1) Represents the fair value on the date of grant of the (i) phantom units granted under the AHD Plan and (ii) phantom units granted under our Plan as well as under our APLMC Plan, all in accordance with prevailing accounting literature.

(2) Represents the fair value on the date of grant of the (i) options granted under the AHD Plan; (ii) options granted under our Plan; and, with respect to Mr. Dubay, (iii) options granted under the Atlas Energy Plan, all in accordance with prevailing accounting literature.

(3) Includes our net cost of $526,768 related to the purchase and subsequent sale of Mr. Dubay s home, calculated by subtracting the sale price and related legal and maintenance expenses from the purchase price and moving expenses of $28,772. Also includes payments of $ 265 with respect to the phantom units awarded under our Plan.

(4) On January 15, 2009, Eugene N. Dubay was appointed serve in the capacity of Chief Executive Officer and President of Atlas Pipeline GP.

(5) On September 7, 2009, Eric T. Kalamaras was appointed Chief Financial Officer of our general partner and of Atlas Pipeline Holdings GP.

(6) Includes a signing bonus of $80,000.

(7) Includes for Messrs. Shrader and Karlovich bonus unit awards made in 2009 under our APLMC Plan and for Mr. Kalamaras an award agreement which, in each case, vest ratably over a three-year period from the date of grant. Consistent with FASB ASC Topic 718 and the assumptions disclosed in Item 8: Financial Statements and Supplementary Data Note 17 , amounts shown include only the amount allocated for the first year of the vesting period; the total amount of the awards is reflected in the Stock awards columns of the Outstanding Equity Awards a Fiscal-Year End Table. These awards are valued based on the closing price of our common units on the grant date. For financial statement purposes, the value of these awards is re-measured as of the end of each reporting period until they vest or are otherwise settled. The value of these awards reflected in Item 8: Financial Statements and Supplementary Data Note 17 Employee Incentive Compensation Plan and Agreement based on the closing price of our common units on December 31, 2009 is as follows: Mr. Kalamaras-$490,500; Mr. Shrader-$490,500; and Mr. Karlovich-$245,250.

(8) On January 15, 2009, Edward E. Cohen resigned as Chief Executive Officer when Eugene N. Dubay was appointed to serve in the capacity of Chief Executive Officer and President of Atlas Pipeline GP.

(9) Includes payments on DERs of $7,200 with respect to the phantom units awarded under our Plan and $5,400 with respect to phantom units awarded under the AHD Plan.

(10) Includes payments on DERs of $2,750 with respect to the phantom units awarded under our Plan and $1,200 with respect to phantom units awarded under the AHD Plan.

(11) Represents payments on DERs of $5,163 with respect to the phantom units awarded under our Plan and $2,700 with respect to phantom units awarded under the AHD Plan.

(12) Includes a $50,000 bonus granted to Mr. Shrader in recognition of his performance in connection with the disposition of our NOARK assets.

Employment Agreements and Potential Payments Upon Termination or Change of Control

Edward E. Cohen

In May 2004, Atlas Energy entered into an employment agreement with Edward E. Cohen, who currently serves as our Chairman and, from 1999 until January 2009, served as our Chief Executive Officer. 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 Compensation Discussion and Analysis, Atlas Energy allocates a portion of Mr. Cohen s compensation cost based on an estimate of the time spent by Mr. Cohen on our activities. Atlas Energy adds 50% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits. The following discussion of Mr. Cohen s employment agreement summarizes those elements of Mr. Cohen s compensation that are allocated in part to us.

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

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The agreement has a term of three years and, until notice to the contrary, the term is automatically extended so that on any day on which the agreement is in effect it has a then-current three-year term. Mr. Cohen s employment agreement was entered into in 2004, around the time that Atlas Energy 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 the then-current President of Atlas Energy. 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 provides 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.

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

Atlas Energy 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 Atlas Energy s Board of Directors or Atlas Energy s material breach of the agreement. Mr. Cohen must provide Atlas Energy with 30 days notice of a termination by him for good reason within 60 days of the event constituting good reason. Atlas Energy 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 Atlas Energy 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 Atlas Energy s then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to three 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 Atlas Energy s employees, during the three years following his termination, (iii) a lump sum amount equal to the cost Atlas Energy would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by Atlas Energy s employees, and (iv) automatic vesting of all stock and option awards.

Mr. Cohen may terminate the agreement without cause with 60 days notice to Atlas Energy, 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.

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Change of control is defined as:

- the acquisition of beneficial ownership, as defined in the Securities Exchange Act of 1933, of 25% or more of Atlas Energy s voting securities or all or substantially all of Atlas Energy s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;

- Atlas Energy consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) Atlas Energy s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless 1/2 of the surviving entity s board were Atlas Energy s directors immediately before the transaction and Atlas Energy s chief executive officer immediately before the transaction continues as the chief executive officer of the surviving entity; or (b) Atlas Energy s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of Atlas Energy, 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 Atlas Energy Board members at the beginning of the period cease for any reason to constitute a majority of the Atlas Energy Board, unless the election or nomination for election by Atlas Energy s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or

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

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. In the event that any amounts payable to Mr. Cohen upon termination become subject to any excise tax imposed under Section 4999 of the Code, Atlas Energy 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.

We anticipate that lump sum termination amounts paid to Mr. Cohen would be allocated to us consistent with past practice and, with respect to payments based on three years of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the prior three-year period. 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, 2009.

Reason for termination	Lump sum severance payment	Benefits(1)	Accelerated vesting of unit awards and option awards(2)	Tax gross- up(3)
Death	$ 442,731(4)	$	$ 506,700	$
Disability	442,731(4)	5,702	506,700	
Termination by us without cause	2,210,077(5)	5,702	506,700	
Termination by Mr. Cohen for good reason	2,210,077(5)	5,702	506,700	
Change of control	2,210,077(5)	5,702	506,700	926,455
Termination by Mr. Cohen without cause	73,789(4)		506,700	

(1) Represents rates currently in effect for COBRA insurance benefits for 36 months.

(2) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2009. 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, 2009.

(3) Calculated after deduction of any excise tax imposed under section 4999 of the Code, and any federal, state and local income tax, FICA and Medicare withholding taxes, taking into account the 20% excess parachute payment rate and a 36.45% combined effective tax rate.

(4) Calculated based on Mr. Cohen s 2009 base salary.

(5) Calculated based on Mr. Cohen s average 2009, 2008 and 2007 base salary and bonus.

Jonathan Z. Cohen

In January 2009, Atlas Energy entered into an employment agreement with Jonathan Z. Cohen, who currently serves as our Vice-Chairman. As discussed above under Compensation Discussion and Analysis, Atlas Energy allocates a portion of Mr. Cohen s compensation cost based on an estimate of the time spent by Mr. Cohen on our activities. The following discussion of Mr. Cohen s employment agreement summarizes those elements of Mr. Cohen s compensation that are allocated in part to us.

Mr. Cohen s employment agreement requires him to devote such time to Atlas Energy as is reasonably necessary to the fulfillment of his duties, although it permits him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $600,000 per year, which may be increased by the Atlas Energy board based upon its evaluation of Mr. Cohen s performance. Mr. Cohen is 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 has a term of three years and, until notice to the contrary, the term is automatically extended so that on any day on which the agreement is in effect it has 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 provides 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.

Atlas Energy 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 Atlas Energy s board determines, in good faith based upon medical evidence, that he is unable to perform his duties. Upon termination by Atlas Energy 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 Atlas Energy 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 our then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum

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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 us, (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 (iv) automatic vesting of all equity-based awards.

Atlas Energy 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 Atlas Energy 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 is defined as:

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

Atlas Energy consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) Atlas Energy s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless 1/2 of the surviving entity s board were our directors immediately before the transaction and Atlas Energy s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) Atlas Energy s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of Atlas Energy, 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 Atlas Energy board members at the beginning of the period cease for any reason to constitute a majority of Atlas Energy s board, unless the election or nomination for election by Atlas Energy s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or

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

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. We anticipate that lump sum termination amounts paid to Mr. Cohen would be allocated to us consistent with past practice and, with respect to payments based on three years of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the prior three-year period. 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, 2009.

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Reason for termination	Lump sum severance payment	Benefits[1]	Accelerated vesting of unit awards and option awards[2]
Death		$	$ 233,850
Termination by us other than for cause (including disability) or by Mr. Cohen for good reason (including a change of control)	1,738,616 [3]		233,850
Termination by us for cause or by Mr. Cohen for other than good reason			

(1) Mr. J. Cohen does not currently receive benefits from Atlas Energy.
(2) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable unit on December 31, 2009. The payments relating to unit awards are calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2009.
(3) Calculated based on Mr. J. Cohen s average 2009, 2008 and 2007 base salary and bonus.

Eugene N. Dubay

In January 2009, Atlas Energy entered into an employment agreement with Eugene N. Dubay, who currently serves as our President and Chief Executive Officer. As discussed above under Compensation Discussion and Analysis, Atlas Energy allocates all of Mr. Dubay s compensation cost to us and Atlas Pipeline Holdings.

The agreement provides 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 will be awarded solely at the discretion of Atlas Energy s 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 Atlas Energy agreed to purchase his residence in Michigan for $1,000,000. If Mr. Dubay s employment is terminated before June 30, 2011 by him without good reason or by Atlas Energy for cause, Mr. Dubay must repay an amount equal to the difference between the amount Atlas Energy paid for his residence and its fair market value on the date acquired by Atlas Energy. Upon execution of the agreement, Mr. Dubay was granted the following equity compensation:

- Options to purchase 100,000 shares of Atlas Energy s common stock, which vest 25% per year on each anniversary of the effective date of the agreement;

- Options to purchase 100,000 of our common units, which vest 25% per year on each anniversary of the effective date of the agreement; and

- Options to purchase 100,000 AHD common units, which vest 25% on the third anniversary, and 75% on the fourth anniversary, of the effective date of the agreement.

The agreement has a term of two years period and, until notice to the contrary, his term is automatically renewed for one year renewal terms. Atlas Energy may terminate the agreement:

- at any time for cause;

- without cause upon 45 days prior written notice;

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if he is physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and our and Atlas Pipeline Holding s board of directors determine, in good faith based upon medical evidence, that he is unable to perform his duties;

in the event of Mr. Dubay s death.

Mr. Dubay has 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 is only effective if such failure has not been cured within 90 days after notice is given to Atlas Energy. Mr. Dubay may 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 is defined as (a) the commitment of a material act of fraud, (b) illegal or gross misconduct that is willful and results in damage to our business or reputation, (c) being charged with a felony, (d) continued failure by Mr. Dubay to perform his duties after notice other than as a result of physical or mental illness, or (e) Mr. Dubay s failure to follow Atlas Energy s reasonable written directions consistent with his duties. Good reason is defined as any action or inaction that constitutes a material breach by Atlas Energy of the agreement or a change of control. Change of control is defined as:

the acquisition of beneficial ownership, as defined in the Securities Exchange Act, of 50% or more of Atlas Energy s voting securities or all or substantially all of Atlas Energy s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Atlas Energy or Mr. Dubay or any member of his immediate family;

Atlas Energy consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction of Atlas Energy other than with a related entity, in which either (a) Atlas Energy s directors immediately before the transaction constitute less than a majority of the board of directors of the surviving entity, unless $^{1}/2$ of the surviving entity s board were Atlas Energy directors immediately before the transaction and Atlas Energy s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) Atlas Energy s voting securities immediately before the transaction represent less than 60% of the combined voting power immediately after the transaction of Atlas Energy, 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 Atlas Energy board members at the beginning of the period cease for any reason to constitute a majority of Atlas Energy s board, unless the election or nomination for the election by Atlas Energy s stockholders of each new director was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of the period; or

Atlas Energy s shareholders approve a plan of complete liquidation or winding-up, or agreement of sale of all or substantially all of Atlas Energy s assets or all or substantially all of the assets of its primary subsidiaries other than to a related entity.

The agreement provides 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.

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Upon termination of employment by Atlas Energy 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 Atlas Energy 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 Atlas Energy 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. We anticipate that lump sum termination amounts paid to Mr. Dubay would be allocated to us consistent with past practice. 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, 2009.

Reason for termination	Lump sum severance payment	Benefits	Accelerated vesting of unit awards and option awards[1]
Death		$ 38,906	$ 1,408,291
Termination by Atlas Energy other than for cause (including disability) or by Mr. Dubay for good reason (including a change of control)	$ 938,847[2]	$ 38,906	$ 1,408,291

(1) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable unit on December 31, 2009. The payments relating to unit awards are calculated by multiplying the number of accelerated shares by the closing price of the applicable stock on December 31, 2009.

(2) Calculated based on Mr. Dubay s 2009 base salary and cash bonus.

Eric T. Kalamaras

In September 2009, Atlas Energy entered into a letter agreement with Eric Kalamaras, who currently serves as our Chief Financial Officer. As discussed above under Compensation Discussion and Analysis, Atlas Energy allocates all of Mr. Kalamaras compensation cost to us and Atlas Pipeline Holdings.

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The agreement provides 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 entitle Mr. Kalamaras, upon vesting, to receive a cash payment equal to the fair market value of our common units. These bonus units vest 1/3 per year over three years, but will vest immediately upon a change of control, Mr. Kalamaras death or if Mr. Kalamaras employment is terminated without cause. If such an event had occurred as of December 31, 2009, the value of the accelerated bonus award would be $490,500 based on the closing price of our common units on that date.

Mr. Kalamaras is 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 provides that Mr. Kalamaras will serve as an at-will employee.

The agreement provides the following regarding termination and termination benefits:

Atlas Energy 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 (a) committed an act of malfeasance or wrongdoing affecting the company or its affiliates, (ii) breached any confidentiality, non-solicitation or non-competition covenant or employment agreement or (iii) otherwise engaged in conduct that would warrant discharge from employment or service because of his negative effect on the company or its affiliates. Change of control means the acquisition by a person or group of (i) more than 50% of the total value of ownership interests or voting interests in Atlas Pipeline Mid-Continent, LLC or APL or (ii) during any 12 month period, assets of either company having a total gross fair market value equal to more than 50% of the total gross fair market value of the assets of the affected company.

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.

Matthew A. Jones

In July 2009, Atlas Energy entered into an employment agreement with Matthew A. Jones, who currently serves as its Chief Financial Officer and, from January 2006 until September 2009, served as our Chief Financial Officer. As discussed above under Compensation Discussion and Analysis, Atlas Energy allocated a portion of Mr. Jones s compensation cost to us based on an estimate of the time spent by Mr. Jones on our activities. Atlas Energy adds 50% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits. The following discussion of Mr. Jones s employment agreement summarizes those elements of Mr. Jones s compensation that were allocated in part to us.

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The agreement provides for initial base compensation of $300,000 per year, which may be increased at the discretion of Atlas Energy s board of directors. Mr. Jones is 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 has a term of two years with the option of renewal at the end of the term.

Atlas Energy may terminate the agreement:

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

Mr. Jones has the right to terminate the agreement for good reason, defined as material breach by Atlas Energy 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. Atlas Energy then would have 30 days in which to cure and, if it does 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 is defined as (a) Mr. Jones having committed a demonstrable and material act of fraud, (b) illegal or gross misconduct that is willful and results in damage to the business or reputation of the Atlas Energy or any of its affiliates, (c) being charged with a felony, (d) continued failure by Mr. Jones to perform his duties after notice other than as a result of physical or mental illness, or (e) Mr. Jones s failure to follow Atlas Energy s reasonable written directions consistent with his duties. Good reason is defined as any action or inaction that constitutes a material breach by us of the agreement or a change of control. Change of control is defined as:

- the acquisition of beneficial ownership, as defined in the Securities Exchange Act, of 50% or more of our voting securities or all or substantially all of our assets by a single person or entity or group of affiliated persons or entities, other than by a related entity, defined as Atlas Energy or any of its affiliates or affiliate of Mr. Jones or any member of his immediate family;
- Atlas Energy s 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) its 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 Atlas Energy s directors immediately before the transaction and its Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) its voting securities immediately before the transaction represent less than 60% of the combined voting power immediately after the transaction of Atlas Energy, the surviving entity or, in the case of a division, each entity resulting from the division;

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- 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 our 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

- Atlas Energy s stockholders approve a plan of complete liquidation or winding-up, or agreement of sale of all or substantially all of Atlas Energy s assets or all or substantially all of the assets of its primary subsidiaries other than to a related entity.

The agreement provides the following regarding termination and termination benefits:

- Upon termination of employment due to death, Mr. Jones 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 the amount of all such incentive compensation would be equal to amount that Mr. Jones earned 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 will immediately vest.

- Upon termination by Atlas Energy for cause or by Mr. Jones for other than good reason, Mr. Jones will 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 will not be subject to forfeiture.

- Upon termination by Atlas Energy other than for cause, including disability, or by Mr. Jones for good reason, he will be entitled to either (a) if Mr. Jones does not sign a release, severance benefits under our then current severance policy, if any, or (b) if Mr. Jones signs a release, (i) a lump sum payment in an amount equal to two 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 date of terminated occurred), less, in the case of termination by reason of disability, any amounts paid under disability insurance provided by Atlas Energy; (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.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. We anticipate that lump sum termination amounts paid to Mr. Jones would be allocated to us consistent with past practice and, with respect to payments based on two years of compensation, would be allocated to us based on the average amount of time Mr. Jones devoted to our activities during the prior three-year period. 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, 2009.

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Reason for termination	Lump sum severance payment	Benefits	Accelerated vesting of unit awards and option awards(1)
Death			$ 113,963
Termination by Atlas Energy other than for cause (including disability) or by Mr. Jones for good reason (including a change of control)	$ 1,255,873(2)	$ 13,617	$ 113,963

(1) Represents the value of unexercisable option and unvested unit awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable units on December 31, 2009. The payments relating to units awards are calculated by multiplying the number of accelerated shares by the closing price of the applicable units on December 31, 2009.

(2) Calculated based on Mr. Jones s 2009 base salary and the average of his 2009, 2008 and 2007 cash bonuses.

Pursuant to their bonus unit awards under the APLMC Plan, Messrs. Shrader and Karlovich are entitled to accelerated vesting of the awards upon a change in control. Change in control means a change in the ownership of APLMC or us, or a change in the ownership of a substantial portion of the assets of either company, provided that:

- no event will be a change in control event unless it is a change in control event as defined in Section 1.409A-3(i)(5) of the Treasury regulations under Section 409A;

- a change in ownership will occur only if ownership interests in either company are acquired by any one person or more than one person acting as a group and, after the acquisition, the acquiring person or persons own more than 50% of the total value or total voting power of such ownership interests; and

- a change in the ownership of a substantial portion of the assets of either company will occur only if one person or more than one person acting as a group acquire during the 12-month period ending on the date of the last such acquisition assets that have a total gross fair market value equal to more than 50% of the total gross fair market value of all the assets of such company.

If such an event had occurred as of December 31, 2009, the value of Mr. Shrader s accelerated bonus units would be $490,500 and the value of Mr. Karlovich s would be $245,250 based on the closing price of our common units on that date.

Our Long-Term Incentive Plan

We have a Long-Term Incentive Plan (the Plan) for officers, employees and non-employee managers of our General Partner and officers and employees of our General Partner s affiliates, consultants and joint venture partners who perform services for us or in furtherance of our business. Our Plan is administered by the Atlas Energy compensation committee, under delegation from our General Partner s managing board. Under our Plan, the compensation committee may make awards of either phantom units or options covering an aggregate of 435,000 common 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 we refer to as a DER, to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions we make on a common unit during the period the phantom unit is outstanding.

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An option entitles the grantee to purchase our 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 our common units on the date of grant. The compensation committee will also have discretion to determine how the exercise price may be paid.

Each non-employee manager of our General Partner receives an annual grant of a maximum of 500 phantom units which, upon vesting, entitles the grantee to receive the equivalent number of common units or the cash equivalent to the fair market value of the units. Our plan was amended by our managing board in February 2010 to increase the pool of phantom units that may be awarded to non-employee managers from 10,000 to 15,000. The total amount of common units that can be awarded under the Plan was not amended. Except for phantom units awarded to non-employee managers of our General Partner, the compensation 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, defined as follows:

Atlas Pipeline Partners GP (or an affiliate of Atlas Energy) ceasing to be our General Partner;

a merger, consolidation, share exchange, division or other reorganization or transaction of us, our General Partner or a direct or indirect parent of our General Partner with any entity, other than a transaction which would result in the voting securities of the us, our General Partner or its parent, as appropriate, outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least 60% of the combined voting power immediately after such transaction of the surviving entity s outstanding securities or, in the case of a division, the outstanding securities of each entity resulting from the division;

the equity holders of us or a direct or indirect parent of our General Partner approve a plan of complete, liquidation or winding-up or an agreement for the sale or disposition (in one transaction or a series of transactions) of all or substantially all of our or such parent s assets; or

during any period of 24 consecutive months, individuals who at the beginning of such period constituted the board of directors of Atlas Pipeline GP or a direct or indirect parent of our General Partner (including for this purpose any new director whose election or nomination for election or appointment was approved by a vote of at least 2/3 of the directors then still in office who were directors at the beginning of such period) cease for any reason to constitute at least a majority of the board or, in the case of a spinoff of the parent, if Edward E. Cohen and Jonathan Z. Cohen cease to be directors of the parent.

If a grantee terminates employment, the grantee s award will be automatically forfeited unless the compensation committee provides otherwise. However, the award will automatically vest if the reason for the termination is the participant s death or disability. Common units to be delivered upon vesting of phantom units or upon exercise of options may be newly issued units, units acquired in the open market or from any of our affiliates, or any combination of these sources at the discretion of the compensation committee. If we issue new common units upon vesting of the phantom units or upon the exercise of options, the total number of common units outstanding will increase. We filed a registration statement with the SEC in order to permit participants to publicly re-sell any common units received by them under the Plan.

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The compensation committee may terminate our Plan at any time with respect to any of the common units for which it has not made a grant. In addition, the compensation committee may amend our Plan from time to time, including, subject to applicable law or the rules of the principal securities exchange on which our common units are traded, increasing the number of common units with respect to which it may grant awards, provided that, without the participant s consent, no change may be made in any outstanding grant that would materially impair the rights of the participant. NYSE rules would require us to obtain unitholder approval for all material amendments to our Plan, including amendments to increase the number of common units issuable under it.

Executive Group Incentive Program

We had incentive compensation agreements which granted awards to certain key employees retained from previously consummated acquisitions. These individuals were entitled to receive our common units upon the vesting of the awards, which was dependent upon the achievement of certain predetermined performance targets through September 30, 2007. At September 30, 2007, the predetermined performance targets were achieved and all of the awards under the incentive compensation agreements vested. Of the total common units issued under the incentive compensation agreements, 58,822 common units were issued during the year ended December 31, 2007. The ultimate number of common units issued under the incentive compensation agreements was determined principally by the financial performance of certain of our assets during the year ended December 31, 2008 and the market value of our common units at December 31, 2008. The incentive compensation agreements also dictated that no individual covered under the agreements would receive an amount of common units in excess of one percent of our outstanding common units at the date of issuance. Common unit amounts due to any individual covered under the agreements in excess of one percent of the outstanding common units would have been paid in cash.

During the year ended December 31, 2009, we issued 348,620 common units to the certain key employees covered under the incentive compensation agreements. No additional common units will be issued with regard to these agreements.

Employee Incentive Compensation Plan and Agreement

The APLMC Plan, adopted in June 2009, allows for equity-indexed cash incentive awards to personnel who perform services for us (the Participants), but expressly excludes as an eligible Participant any of our Named Executive Officers (as such term is defined under the rules of the Securities and Exchange Commission) at the time of the award. The APLMC Plan is administered by a committee appointed by our chief executive officer. Under the APLMC Plan, cash bonus units may be awarded Participants at the discretion of the committee and bonus units totaling 325,000 were awarded under the Incentive Plan during the year ended December 31, 2009. In September 2009, Mr. Kalamaras was separately awarded 50,000 bonus units on substantially the same terms as the bonus units available under the APLMC Plan (the bonus units issued under the Incentive Plan and under the separate agreement are, for purposes hereof, referred to as bonus units). A bonus unit entitles the employee to receive the cash equivalent of the then-fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the bonus unit. Bonus units vest ratably over a three year period from the date of grant and will automatically vest upon a change of control, death, or termination without cause, each as defined in the governing document. Vesting will terminate upon termination of employment with cause. During the year ended December 31, 2009, we granted 375,000 bonus units.

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AHD Plan

The AHD Plan provides equity incentive awards to officers, employees and board members and employees of its affiliates, consultants and joint-venture partners who perform services for Atlas Pipeline Holdings. The AHD Plan is administered by Atlas Energy s compensation committee under delegation from the Atlas Pipeline Holdings board. The compensation committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 common limited partner units.

Partnership Phantom Units. A phantom unit entitles a participant to receive an Atlas Pipeline Holdings common unit upon vesting of the phantom unit. Non-employee directors receive an annual grant of a maximum of 500 phantom units 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. In tandem with phantom unit grants, the compensation committee may grant a DER. The compensation committee determines the vesting period for phantom units. Phantom units granted under the AHD Plan generally vest 25% on the third anniversary of the date of grant and 75% 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 compensation committee on the date of grant of the option. The compensation committee determines the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Unit options generally will vest 25% on the third anniversary of the date of grant and 75% on the fourth anniversary of the date of grant. Awards will automatically vest upon a change of control, as defined in the AHD Plan.

Atlas Energy Plans

Atlas Energy s Stock Incentive Plan (the 2004 Plan) authorizes the granting of up to 4.5 million shares of its common stock to its employees, affiliates, consultants and directors in the form of incentive stock options (ISOs), non-qualified stock options, stock appreciation rights (SARs), restricted stock and deferred units. Atlas Energy also has a 2009 Stock Incentive Plan (the 2009 Plan) which authorizes the granting of up to 4.8 million shares of its common stock to its employees, affiliates, consultants and directors in the form of ISOs, non-qualified stock options, SARs, restricted stock, restricted stock units and deferred units. SARs represent a right to receive cash in the amount of the difference between the fair market value of a share of Atlas Energy s common stock on the exercise date and the exercise price, and may be free-standing or tied to grants of options. A deferred unit or a restricted stock unit represents the right to receive one share of Atlas Energy s common stock upon vesting. Generally, awards under the 2004 Plan and 2009 Plan become exercisable 25% on each anniversary after the date of grant except that deferred units awarded to Atlas Energy s non-executive board members vest 33$^{1}/_{3}$% on each of the second, third and fourth anniversaries of the grant, and expire not later than ten years after the date of grant.

As required by SEC guidelines, the following table disclosed awards under our Plan as well as under the AHD Plan and Atlas Energy s Plans.

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OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END TABLE

Name	Option Awards Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Stock Awards Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)
Eugene N. Dubay		100,000(1)	$ 13.35	01/15/2019		
		100,000(2)	6.24	01/15/2019	375(3)	$ 3,679(4)
		100,000(5)	3.24	01/15/2019		
Eric Kalamaras					50,000(6)	490,500(4)
Edward E. Cohen					5,000(7)	49,050(4)
	125,000	375,000(8)	22.56	11/10/2016	67,500(9)	457,650(10)
Matthew A. Jones					1,250(7)	12,263(4)
	25,000	75,000(8)	22.56	11/10/2016	15,000(9)	101,700(10)
Jonathan Z. Cohen					3,750(7)	36,788(4)
	50,000	150,000(8)	22.56	11/10/2016	11,250(9)	76,275(10)
Gerald R. Shrader					750(11)	7,358(4)
					50,000(12)	490,500(4)
Robert W. Karlovich III					750(11)	7,358(4)
					25,000(13)	245,250(4)

(1) Represents options to purchase Atlas Energy common stock, which vests as follows: 01/15/2010 25,000; 01/15/2011 25,000; 01/15/2012 25,000 and 01/15/2013 25,000.

(2) Represents options to purchase our common units, which vest as follows: 01/15/2010 25,000; 01/15/2011 25,000; 01/15/2012 25,000 and 01/15/2013 25,000.

(3) Represents our phantom units, which vest as follows: 10/14/2010 125; 10/14/2011 125 and 10/14/2012 125.

(4) Based on closing market price of our common units on December 31, 2009 of $9.81.

(5) Represents options to purchase Atlas Pipeline Holdings units, which vest as follows: 01/15/2012 25,000 and 01/15/2013 75,000.

(6) Includes our bonus units which vest as follows: 9/14/2010-16,667; 9/14/2011-16,667 and 9/14/2012-16,666. See Item 8: Financial Statements and Supplementary Data Note 17 - Employee Incentive Compensation Plan and Agreement.

(7) Represents our phantom units, which vest on 11/01/2010.

(8) Represents Atlas Pipeline Holdings options, which vest on 11/10/2010.

(9) Represents Atlas Pipeline Holdings phantom units, which vest on 11/10/2010.

(10) Based on closing market price of Atlas Pipeline Holdings common units on December 31, 2009 of $ 6.78.

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(11) Represents our phantom units, which vest as follows: 03/03/2010 250; 03/03/2011 250 and 03/03/12 250.

(12) Includes our bonus units which vest as follows: 6/1/2010-16,667; 6/1/2011-16,667 and 6/1/2012-16,666. See Item 8: Financial Statements and Supplementary Data Note 17 - Employee Incentive Compensation Plan and Agreement.

(13) Includes our bonus units which vest as follows: 6/1/2010-8,333; 6/1/2011-8,333 and 6/1/2012-8,333. See Item 8: Financial Statements and Supplementary Data Note 17 - Employee Incentive Compensation Plan and Agreement.

2009 OPTION EXERCISES AND STOCK VESTED TABLE

Name	Stock Awards: Number of Units Acquired on Vesting	Stock Awards: Value Realized on Vesting ($)
Eugene E. Dubay	125(1)	$ 2,708
Edward E. Cohen	32,500(2)	802,850
Matthew A. Jones	10,000(3)	289,363
Jonathan Z. Cohen	18,125(4)	449,550
Gerald R. Shrader	250(1)	11,128
Robert W. Karlovich, III	250(1)	11,128

(1) Represents Atlas Pipeline Partners common units.

(2) Represents 10,000 common units of Atlas Pipeline Partners and 22,500 common units of Atlas Pipeline Holdings.

(3) Represents 5,000 common units of Atlas Pipeline Partners and 5,000 common units of Atlas Pipeline Holdings.

(4) Represents 6,875 common units of Atlas Pipeline Partners and 11,250 common units of Atlas Pipeline Holdings.

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	All Other Compensation ($)(1)	Total ($)
Tony C. Banks	$ 35,000	$ 3,435(2)	$ 471	$ 38,906
Curtis D. Clifford	35,000	2,600(3)	532	38,132
Martin Rudolph	35,000	2,600(4)	490	37,220
Gayle P.W. Jackson	18,736	2,600(4)	490	20,956
Michael Staines(5)				

(1) Represents payments on DERs for phantom units.

(2) Represents 500 phantom units granted under our Plan, having a grant date fair value of $6.87. The phantom units vest 25% on each anniversary of the date of grant as follows: 2/11/10 125, 2/11/11 125, 2/11/12 125 and 2/11/13 125.

(3) Represents 500 phantom units granted under our Plan, having a grant date fair value of $5.20. The phantom units vest 25% on each anniversary of the date of grant as follows: 5/10/10 125, 5/10/11 125, 5/10/12 125 and 5/10/13 125.

(4) Represents 500 phantom units granted to Mr. Rudolph and Dr. Jackson under our Plan, having a grant date fair value of $5.20. The phantom units vest 25% on each anniversary of the date of grant as follows: 5/10/10 125, 5/10/11 125, 5/10/12 125 and 5/10/13 125. The vesting of Dr. Jackson s phantom units were accelerated in connection with her election to the Atlas Energy board and her resignation from our board.

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(5) Mr. Staines resigned from employment with Atlas Energy as of July 2009, but remains a managing board member. As a part of his separation arrangement, he will not receive a director s fee until July 2010.

Our General Partner does not pay additional remuneration to officers or employees of Atlas Energy who also serve as managing board members. In fiscal year 2009, each non-employee managing board member received an annual retainer of $35,000 in cash and an annual grant of phantom units with DERs in an amount equal to the lesser of 500 units or $15,000 worth of units (based upon the market price of our common units) pursuant to our Plan. In addition, our General Partner reimburses each non-employee board member 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 managing board members for actions associated with serving as managing board members to the extent permitted under Delaware law.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The following table sets forth the number and percentage of shares of common stock owned, as of March 2, 2010, by (a) each person who, to our knowledge, is the beneficial owner of more than 5% of the outstanding shares of common stock, (b) each of the members of the managing board of our General Partner, (c) each of the executive officers named in the Summary Compensation Table in Item 11, and (d) all of the named executive officers and board members as a group. This information is reported in accordance with the beneficial ownership rules of the Securities and Exchange Commission under which a person is deemed to be the beneficial owner of a security if that person has or shares voting power or investment power with respect to such security or has the right to acquire such ownership within 60 days. Unless otherwise indicated in footnotes to the table, each person listed has sole voting and dispositive power with respect to the securities owned by such person. The address of our General Partner, its executive officers and managing board members is 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108.

Name of Beneficial Owner	Common Units	Percent of Class
Executive officers and Members of the Managing Board		
Edward E. Cohen	84,200	*
Jonathan Z. Cohen	49,727	*
Eugene N. Dubay	27,125[(1)]	*
Matthew A. Jones	18,750	*
Eric T. Kalamaras	0	*
Tony C. Banks	1,374	*
Robert W. Karlovich	500	*
Gerald R. Shrader	500	*
Curtis D. Clifford	2,081	*
Martin Rudolph	1,721	*
Michael L. Staines	12,000	*
Executive officers and Managing Board Members as a group (11 persons)	197,978	*
Other Owners of More than 5% of Outstanding Units		
Atlas Pipeline Holdings, L.P.	4,113,227	8.14%
Leon Cooperman	4,757,418[(2)]	9.4%

* Less than 1%.

(1) Includes 25,000 vested options.

(2) This information is based upon a Schedule 13G which was filed with the SEC on February 4, 2009. The address for Mr. Cooperman is 88 Pine Street, Wall Street Plaza 31 Floor, New York, NY 10005.

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Equity Compensation Plan Information

The following table contains information about our Plan as of December 31, 2009:

Plan category	(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders phantom units	52,233	n/a	
Equity compensation plans approved by security holders unit options	100,000	$ 6.24	
Equity compensation plans approved by security holders Total	152,233		66,584

The following table contains information about the AHD Plan as of December 31, 2009:

Plan category	(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders phantom units	138,875	n/a	
Equity compensation plans approved by security holders unit options	955,000	$ 20,54	
Equity compensation plans approved by security holders Total	1,093,875		960,650

The following table contains information about Atlas Energy Plans as of December 31, 2009:

Plan category	(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders restricted units	46,999	n/a	
Equity compensation plans approved by security holders options	3,509,554	$ 16.82	
Equity compensation plans approved by security holders Total	3,556,553		5,544,137

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

We do not directly employ any persons to manage or operate our business. These functions are provided by our General Partner and employees of Atlas Energy. Our General Partner does not receive a management fee in connection with its management of our operations, but we reimburse our General Partner and its affiliates for compensation and benefits related to Atlas Energy employees who perform services to us, based upon an estimate of the time spent by such persons on our activities. 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 our activities. Our partnership agreement provides that our General Partner will determine the costs and expenses that are allocable to us in any reasonable manner determined at its sole discretion. We reimbursed our General Partner and its affiliates $2.7 million for the year ended December 31, 2009 for compensation and benefits related to their employees. Our General Partner believes that the method utilized in allocating costs to us is reasonable.

Effective as of April 30, 2009, Atlas Pipeline GP adopted a written policy governing related party transactions. For purposes of this policy, a related party includes: (i) any executive officer, director or director nominee; (ii) any person known to be a beneficial owner of 5% or more of our common units; (iii) an immediate family member of any person included in clauses (i) and (ii) (which, by definition, includes, a person s spouse, parents and parents in law, step parents, children, children in law and stepchildren, siblings and brothers and sisters in law and anyone residing in the that person s home); and (iv) any firm, corporation or other entity in which any person included in clauses (i) through (iii) above is employed as an executive officer, is a director, partner, principal or occupies a similar position or in which that person owns a 5% or more beneficial interest. With certain exceptions outlined below, any transaction between us and a related party that is anticipated to exceed $120,000 in any calendar year must be approved, in advance, by the Conflicts Committee of Atlas Pipeline GP. If approval in advance is not feasible, the related party transaction must be ratified by the Conflicts Committee. In approving a related party transaction the Conflicts Committee will take into account, in addition to such other factors as the Conflicts Committee deems appropriate, the extent of the related party s interest in the transaction and whether the transaction is no less favorable to us than terms generally available to an unaffiliated third party under similar circumstances.

The following related party transactions are pre-approved under the policy: (i) employment of an executive officer to perform services on our behalf (or on behalf of one of our subsidiaries); (ii) compensation paid to directors for serving on the board of Atlas Pipeline GP or any committee thereof; (iii) transactions where the related party s interest arises solely as a holder of our common units and such interest is proportional to all other owners of common units or a transaction (e.g. participation in health plans) that are available to all employees generally; (iv) a transaction at another company where the related party is only an employee (and not an executive officer), director or beneficial owner of less than 10% of such company s shares and the aggregate amount involved does not exceed the greater of $1,000,000 or 2% of that firm s total annual revenues; and (v) any charitable contribution, grant or endowment by us or Atlas Pipeline GP to a charitable organization, foundation or university at which the related party s only relationship is as an employee (other than an executive officer) or director or similar capacity, if the aggregate amount involved does not exceed the greater of $5,000 or 2% of that organization s total receipts. We are not aware of any related party transactions requiring approval under the policy that were undertaken in 2009.

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ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees recognized by us during the years ended December 31, 2009 and 2008 by our principal accounting firm, Grant Thornton LLP, are set forth below:

	2009	2008
Audit fees (1)	$ 1,635,120	$ 1,943,280
Audit related fees	100,500	
Tax fees (2)	120,157	165,750
All other fees		
Total aggregate fees billed	$ 1,855,777	$ 2,109,030

(1) Represents the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP for the audit of our annual financial statements and the review of financial statements included in Form 10-Q. The fees are for services that are normally provided by Grant Thornton LLP in connection with statutory or regulatory filings or engagements.

(2) Represents the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP for tax compliance, tax advice, and tax planning.

Audit Committee Pre-Approval Policies and Procedures

Pursuant to its charter, the audit committee of the managing board of our General Partner is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent auditors. All of such services and fees were pre-approved during 2009 and 2008.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

(2) Financial Statement Schedules
No schedules are required to be presented.

(3) Exhibits:

Exhibit No.	Description
3.1	Certificate of Limited Partnership(1)
3.2(a)	Second Amended and Restated Agreement of Limited Partnership(2)
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership(3)
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership(4)
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership(6)
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership(7)
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership(11)
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership(13)
3.3	Amended and Restated Certificate of Designation for 12% Cumulative Convertible Class B Preferred Units(13)
4.1	Common unit certificate(1)
4.2	8 1/8% Senior Notes Indenture dated December 20, 2005(12)
4.3	8 3/4% Senior Notes Indenture dated June 27, 2008(9)
10.1(a)	Revolving Credit and Term Loan Agreement dated July 27, 2007 by and among Atlas Pipeline Partners, L.P., Wachovia Bank, National Association and the several guarantors and lenders hereto(4)

10.1(b)	Amendment No. 1 and Agreement to the Revolving Credit and Term Loan Agreement, dated June 12, 2008[(7)]
10.1(c)	Increase Joinder dated June 27, 2008[(10)]
10.1(d)	Amendment No. 2 to Revolving Credit and Term Loan Agreement, dated May 29, 2009 [(14)]
10.2	Class B Preferred Unit Purchase Agreement dated December 30, 2008, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P.[(11)]
10.3	Registration Rights Agreement dated December 30, 2008, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P. [(11)]
10.4	Purchase Agreement dated as of January 27, 2009, between Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, Sunlight Capital Partners, LLC, Elliott Associates, L.P. and Elliott International, L.P. [(5)]
10.5	Form of Common Unit Purchase Agreement dated August 17, 2009, by and among Atlas Pipeline Partners, L.P. and the purchasers party thereto[(15)]
10.6	Form of Registration Rights Agreement dated August 20, 2009, by and among Atlas Pipeline Partners, L.P. and the purchasers party thereto [(15)]
10.7	Form of Warrant to purchase common units dated August 20, 2009[(15)]
10.8	Form of First Amendment to Warrant to purchase common units dated January 7, 2010[(22)]
10.9	Purchase Option Agreement between Atlas Pipeline Mid-Continent WestTex, LLC and Pioneer Natural Resources USA, Inc. dated July 27, 2007[(4)]
10.10	Long-Term Incentive Plan
10.11	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan
10.12	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement
10.13	Formation and Exchange Agreement dated March 31, 2009 between Williams Field Services Group, LLC, Williams Laurel Mountain, LLC, Atlas Pipeline Partners, L.P., Atlas Pipeline Operating Partnership, L.P. and APL Laurel Mountain, LLC[(17)]

10.14	Employment Agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay[(17)]
10.15	Securities Purchase Agreement dated April 7, 2009, by and between Atlas Pipeline Mid-Continent, LLC and Spectra Energy Partners OLP, LP[(18)]
10.16(a)	Revolving Credit Agreement among Atlas Pipeline Holdings, L.P., Atlas Pipeline Partners GP, LLC, Wachovia Bank, National Association, and other banks party thereto, dated as of July 26, 2006[(18)]
10.16(b)	First Amendment to the Revolving Credit Agreement dated June 1, 2009, by and among Atlas Pipeline Holdings, L.P., Atlas Pipeline Partners GP, LLC, Wachovia Bank, National Association and the lenders thereunder[(19)]
10.17	Atlas Pipeline Holdings II, LLC Limited Liability Company Agreement[(19)]
10.18	ATN Option Agreement dated as of June 1, 2009, by and among APL Laurel Mountain, LLC, Atlas Pipeline Operating Partnership, L.P. and Atlas Energy Resources, LLC[(20)]
10.19	Amended and Restated Limited Liability Company Agreement of Laurel Mountain Midstream, LLC dated as of June 1, 2009[(20)]
10.20	Letter Agreement, dated as of August 31, 2009, between Atlas America, Inc. and Eric Kalamaras[(21)]
10.21	Phantom Unit Grant Agreement between Atlas Pipeline Mid-Continent, LLC and Eric Kalamaras, dated September 14, 2009[(21)]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Registrant
23.1	Consent of Grant Thornton LLP
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification

32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(5) Previously filed as an exhibit to current report on Form 8-K on January 29, 2009.
(6) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
(7) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
(8) [Intentionally Omitted]
(9) Previously filed as an exhibit to current report on Form 8-K on June 27, 2008.
(10) Previously filed as an exhibit to current report on Form 8-K on July 3, 2008.
(11) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
(12) Previously filed as an exhibit to current report on Form 8-K on December 21, 2005.
(13) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
(14) Previously filed as an exhibit to current report on Form 8-K on June 1, 2009.
(15) Previously filed as an exhibit to current report on Form 8-K on August 20, 2009.
(16) Previously filed as an exhibit to annual report on Form 10-K for the year ended December 31, 2008.
(17) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2009.
(18) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2009.
(19) Previously filed as an exhibit to current report on Form 8-K on June 2, 2009.
(20) Previously filed as an exhibit to current report on Form 8-K on June 5, 2009.
(21) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2009.
(22) Previously filed as an exhibit to current report on Form 8-K on January 8, 2010.

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SIGNATURES

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

ATLAS PIPELINE PARTNERS, L.P.

By: Atlas Pipeline Partners GP, LLC,
its General Partner

March 5, 2010

By: /s/ EUGENE N. DUBAY
Chief Executive Officer, President and Managing Board Member of the General Partner

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of March 5, 2010.

/s/ EDWARD E. COHEN **Edward E. Cohen**	Chairman of the Managing Board of the General Partner
/s/ JONATHAN Z. COHEN **Jonathan Z. Cohen**	Vice Chairman of the Managing Board of the General Partner
/s/ EUGENE N. DUBAY **Eugene N. Dubay**	Chief Executive Officer, President and Managing Board Member of the General Partner
/s/ ERIC T. KALAMARAS **Eric T. Kalamaras**	Chief Financial Officer of the General Partner
/s/ ROBERT W. KARLOVICH III **Robert W. Karlovich III**	Chief Accounting Officer of the General Partner
/s/ TONY C. BANKS **Tony C. Banks**	Managing Board Member of the General Partner
/s/ CURTIS D. CLIFFORD **Curtis D. Clifford**	Managing Board Member of the General Partner
/s/ MARTIN RUDOLPH **Martin Rudolph**	Managing Board Member of the General Partner
/s/ MICHAEL L. STAINES **Michael L. Staines**	Managing Board Member of the General Partner