LEGACY RESERVES LP
Form 10-K/A
December 11, 2008

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K/A
Amendment No. 2

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2007**
	OR
o	**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 1-33249

Legacy Reserves LP
(Exact name of registrant as specified in its charter)

Delaware	**16-1751069**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
303 W. Wall Street, Suite 1400 **Midland, Texas** *(Address of principal executive offices)*	**79701** *(Zip Code)*

Registrant s telephone number, including area code:
(432) 689-5200

Securities registered pursuant to Section 12(b) of the Act:
Units representing limited partner interests listed on the NASDAQ Stock Market LLC.

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

None.

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

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

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 þ No o

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 the 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. þ

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 the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of units held by non-affiliates was approximately $459,526,531 based on the average bid and ask price of the units as of June 29, 2007.

29,671,470 units representing limited partner interests in the registrant were outstanding as of March 14, 2008.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant s 2008 annual meeting of unitholders are incorporated by reference into Part III of this annual report on Form 10-K.

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Explanatory Note

Legacy Reserves LP filed an Annual Report on Form 10-K with the Securities and Exchange Commission on March 14, 2008 for the fiscal year ended December 31, 2007 (the Original Filing) and an amendment to its Form 10-K on March 27, 2008. This Amendment No. 2 amends the Original Filing and the Form 10-K/A filed on March 27, 2008, and is being filed solely for the purpose of correcting a typographical error contained in Exhibit 32.1 of the Original Filing. The remainder of the Form 10-K is unchanged and is reproduced in this Amendment No. 2. This Amendment No. 2 speaks as of the file date of the Original Filing and does not reflect events occurring after the filing date of the Original Filing, or modify or update the disclosures therein in any way other than as required to reflect the amendment described above.

LEGACY RESERVES LP

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GLOSSARY OF TERMS

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Boe. One barrel of oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development Project. A drilling or other project which may target proven reserves, but which generally has a lower risk than that associated with exploration projects.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved developed non-producing or PDNP s. Proved oil and natural gas reserves that are developed behind pipe, shut-in or can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

Proved reserves. Proved oil and natural gas reserves are the estimated quantities of natural gas, crude oil and natural gas liquids that geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or PUDs. Proved oil and natural gas reserves that are expected to be recovered from new wells on un-drilled acreage or from existing wells where a relatively major expenditure is required for re-completion. Reserves on un-drilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other un-drilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserve acquisition cost. The total consideration paid for an oil and natural gas property or set of properties, which includes the cash purchase price and any value ascribed to units issued to a seller adjusted for any post-closing items.

R/P ratio (reserve life). The reserves as of the end of a period divided by the production volumes for the same period.

Reserve replacement. The replacement of oil and natural gas produced with reserve additions from acquisitions, reserve additions and reserve revisions.

Reserve replacement cost. An amount per BOE equal to the sum of costs incurred relating to oil and natural gas property acquisition, exploitation, development and exploration activities (as reflected in our year-end financial statements for the relevant year) divided by the sum of all additions and revisions to estimated proved reserves, including reserve purchases. The calculation of reserve additions for each year is based upon the reserve report of our independent engineers. Management uses reserve replacement cost to compare our company to others in terms of our historical ability to increase our reserve base in an economic manner. However, past performance does not necessarily reflect future reserve replacement cost performance. For example, increases in oil and natural gas prices in recent years have increased the economic life of reserves adding additional reserves with no required capital expenditures. On the other hand, increases in oil and natural gas prices have increased the cost of reserve purchases and reserves added through development projects. The reserve replacement cost may not be indicative of the economic value added of the reserves due to differing lease operating expenses per barrel and differing timing of production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

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Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provisions for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

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CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING INFORMATION

This document contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- our business strategy;
- the amount of oil and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- our ability to acquire additional oil and natural gas properties at economically attractive prices;
- our drilling location and our ability to continue our development activities at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and finding and development costs, including payments to our general partner;
- the level of our capital expenditures;
- our future operating results; and
- our plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this document, are forward-looking statements. In some cases, you can identify forward-looking statements by terminology such as may, could, should, expect, plan, project, intend, anticipate, believe, estimate, predict, potential, pursue, target, c such terms or other comparable terminology.

The forward-looking statements contained in this document are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this document are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in Item 1A. under Risk Factors. The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly.

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PART I

ITEM 1. *BUSINESS*

References in this annual report on Form 10-K to Legacy Reserves, Legacy, we, our, us, or like terms prior to March 15, 2006 refer to the Moriah Group, Legacy Reserves LP s predecessor, including the oil and natural gas properties we acquired in exchange for units and cash from the Moriah Group, the Brothers Group, H2K Holdings, MBN Properties (our Founding Investors) and certain charitable foundations in connection with our private equity offering on March 15, 2006. When used for periods from March 15, 2006 forward, those terms refer to Legacy Reserves LP and its subsidiaries.

Legacy Reserves LP

We are an independent oil and natural gas limited partnership headquartered in Midland, Texas, and are focused on the acquisition and development of oil and natural gas properties primarily located in the Permian Basin and Mid-continent regions of the United States. We were formed in October 2005 to own and operate the oil and natural gas properties that we acquired from our Founding Investors and three charitable foundations in connection with the closing of our private equity offering on March 15, 2006. On January 18, 2007, we completed our initial public offering.

Our primary business objective is to generate stable cash flows allowing us to make cash distributions to our unitholders and to increase quarterly cash distributions per unit over time through a combination of acquisitions of new properties and development of our existing oil and natural gas properties.

We have grown primarily through two activities: the acquisition of producing oil and natural gas properties and the development of producing properties as opposed to higher risk exploration of unproved properties.

Our oil and natural gas production and reserve data as of December 31, 2007 are as follows:

- we had proved reserves of approximately 32.1 MMBoe, of which 74% were oil and natural gas liquids and 87% were classified as proved developed producing, 3% were proved developed non-producing, and 10% were proved undeveloped;

- our proved reserves had a standardized measure of $690.5 million; and

- our proved reserves to production ratio was approximately 14 years based on the average daily net production of 6,453 Boe/d for the three months ended December 31, 2007.

Recent Developments

On November 8, 2007 we closed a private placement of 3,642,369 Units for $20.50 per unit for net proceeds of approximately $73.0 million. We used the net proceeds of the private placement primarily to reduce debt outstanding under or revolving credit facility.

Acquisition Activities

During the year ended December 31, 2007, we invested approximately $200.4 million, including non-cash asset retirement obligations, in 15 acquisitions of proved oil and natural gas properties. Based on reserve data prepared internally at the time of these acquisitions, we added a total of approximately 14.25 MMBoe of proved reserves at an average reserve acquisition cost of $13.59 per Boe, which excludes associated non-cash asset retirement obligations. The recent acquisitions discussed below are also included in the reserve acquisition cost calculation, along with immaterial acquisitions closed during 2007.

On April 16, 2007, Legacy purchased certain oil and natural gas properties and other interests in the East Binger (Marchand) Unit in Caddo County, Oklahoma from Nielson & Associates, Inc. for a net purchase price of $44.2 million (Binger Acquisition). The purchase price was paid with the issuance of 611,247 units valued at $15.8 million and $28.4 million paid in cash. The effective date of this purchase was February 1, 2007. The $44.2 million purchase price was allocated with $14.7 million recorded as lease and well equipment, $29.4 million of leasehold costs and $0.1 million as investment in equity method investee related to the 50% interest acquired in Binger Operations, LLC. Asset retirement obligations of $184,636 were recorded in connection with this acquisition. The operations of these Binger Acquisition properties have been included from their acquisition on April 16, 2007.

On May 1, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Ameristate Exploration, LLC for a net purchase price of $5.2 million (Ameristate Acquisition). The effective date of this purchase was January 1, 2007. The $5.2 million purchase price was allocated with $0.5 million recorded as lease and well equipment and $4.7 million of leasehold costs. Asset retirement obligations of $51,414 were recorded in connection with this acquisition. The operations of these Ameristate Acquisition properties have been included from their acquisition on May 1, 2007.

On May 25, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Terry S. Fields for a net purchase price of $14.7 million (TSF Acquisition). The effective date of this purchase was March 1, 2007. The $14.7 million purchase price was allocated with $1.8 million recorded as lease and well equipment and $12.9 million of leasehold costs. Asset retirement obligations of $99,094 were recorded in connection with this acquisition. The operations of these TSF Acquisition properties have been included from their acquisition on May 25, 2007.

On May 31, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Raven Resources, LLC and Shenandoah Petroleum Corporation for a net purchase price of $13.0 million (Raven Shenandoah Acquisition). The effective date of this purchase was May 1, 2007. The $13.0 million purchase price was allocated with $6.0 million recorded as lease and well equipment and $7.0 million of leasehold costs. Asset retirement obligations of $378,835 were recorded in connection with this acquisition. The operations of these Raven Shenandoah Acquisition properties have been included from their acquisition on May 31, 2007.

On August 3, 2007, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin from Raven Resources, LLC and private parties for a net purchase price of $20.0 million (Raven OBO Acquisition). The effective date of this purchase was July 1, 2007. The $20.0 million purchase price was allocated with $1.6 million recorded as lease and well equipment and $18.4 million of leasehold costs. Asset retirement obligations of $224,329 were recorded in connection with this acquisition. The operations of these Raven OBO Acquisition properties have been included from their acquisition on August 3, 2007.

On October 1, 2007, Legacy purchased certain oil and natural gas properties located in the Texas Panhandle from The Operating Company, et al, for a net purchase price of $60.5 million (TOC Acquisition). The effective date of this purchase was September 1, 2007. The $60.5 million purchase price was allocated with $23.7 million recorded as lease and well equipment and $36.8 million of leasehold costs. Asset retirement obligations of $1.6 million were recorded in connection with this acquisition. The operations of these TOC Acquisition properties have been included from their acquisition on October 1, 2007.

Also on October 1, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Summit Petroleum Management Corporation for a net purchase price of $13.4 million (Summit Acquisition). The effective date of this purchase was September 1, 2007. The $13.4 million purchase price was allocated with $2.1 million recorded as lease and well equipment and $11.3 million of leasehold cost. Asset retirement obligations of $128,705 were recorded in connection with this acquisition. The operations of these Summit Acquisition properties have been included from their acquisition on October 1, 2007.

During November and December, 2007, Legacy purchased certain oil and natural gas properties from multiple parties in the Permian Basin and Texas Panhandle for an aggregate $17.8 million. The acquisitions have various effective dates. The $17.8 million purchase price was allocated with $4.5 million recorded as lease and well equipment and

$13.3 million of leasehold cost. The operations of these acquired properties have been included from their acquisition dates over November and December, 2007.

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Development Activities

We have also added reserves and production through development projects on our existing and acquired properties. Our development projects include accessing additional productive formations in existing well-bores, formation stimulation, artificial lift equipment enhancement, infill drilling on closer well spacing, secondary (waterflood) and tertiary (miscible CO_2 and nitrogen) recovery projects, drilling for deeper formations and completing unconventional and tight formations.

As of December 31, 2007, we identified 109 gross (72.8 net) proved undeveloped drilling locations and 43 gross (16 net) re-completion and re-fracture stimulation projects, over 93% of which we intend to drill and execute over the next four years. Excluding acquisitions, we expect to make capital expenditures of approximately $18.2 million during the year ending December 31, 2008, including drilling 24 gross (17.3 net) development wells and executing 12 gross (5.8 net) re-completions and re-fracture stimulations. We believe that drilling rigs will be available to execute our 2008 development program.

Oil and Natural Gas Derivative Activities

Our strategy includes entering into oil and natural gas derivative contracts which are designed to mitigate price risk for a majority of our oil, NGL and natural gas production over a three to five-year period. We have entered into these derivative contracts for approximately 73% of our expected oil and natural gas production from total proved reserves for the year ending December 31, 2008. We have also entered into these derivative contracts for approximately 54% of our expected oil and natural gas production from total proved reserves for 2009 through 2012. All of our derivative contracts are in the form of fixed price swaps for NYMEX WTI oil, Mont Belvieu OPIS natural gas liquids components, NYMEX Henry Hub natural gas, West Texas Waha natural gas and ANR-Oklahoma natural gas. In July 2006, we entered into basis swaps to receive floating NYMEX Henry Hub natural gas prices less a fixed basis differential and pay prices based on the floating Waha index, a natural gas hub in West Texas. The prices that we receive for our Permian Basin natural gas sales follow Waha more closely than NYMEX Henry Hub. The basis swaps, thereby, provide a better match between our natural gas sales and the settlement payments on our natural gas swaps. We have entered into basis swaps covering approximately 100% of our NYMEX Henry Hub natural gas basis differential risk on our NYMEX Henry Hub natural gas swaps.

Business Strategy

The key elements of our business strategy are to:

- Make accretive acquisitions of producing properties generally characterized by long-lived reserves with stable production and reserve development potential;
- Add proved reserves and maximize cash flow and production through development projects and operational efficiencies;
- Maintain financial flexibility; and
- Reduce commodity price risk through derivative transactions.

Marketing and Major Purchasers

For the years ended December 31, 2005, 2006 and 2007, Legacy sold oil and natural gas production representing 10% or more of total revenues to purchasers as detailed in the table below:

	2005	2006	2007
Conoco Phillips	10%	4%	3%
Navajo Crude Oil Marketing	16%	12%	11%
Plains Marketing, LP	18%	14%	13%
Teppco Crude Oil, LP	5%	5%	13%

Our oil sales prices are based on formula pricing and calculated either using a discount to NYMEX WTI oil or using the appropriate buyer s posted price, plus Platt s P-Plus monthly average, plus the Midland-Cushing differential less a transportation fee.

If we were to lose any one of our oil or natural gas purchasers, the loss could temporarily cause a loss or deferral of production and sale of our oil and natural gas in that particular purchaser s service area. If we were to lose a purchaser, we believe we could identify a substitute purchaser. However, if one or more of our larger purchasers ceased purchasing oil or natural gas altogether, the loss of such purchasers could have a detrimental effect on our production volumes in general and on our ability to find substitute purchasers for our production volumes in a timely manner.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

We are also affected by competition for drilling rigs, completion rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which has delayed development drilling and other development projects and has caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our development program.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months thereby affecting the price we receive for natural gas. Seasonal anomalies such as mild winters or hotter than normal summers sometimes lessen this fluctuation.

Environmental Matters and Regulation

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

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The following is a summary of some of the existing laws, rules and regulations to which our operations are subject.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non- hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

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

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

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Air Emissions. The Federal Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the

Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

OSHA and Other Laws and Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in compliance with these applicable requirements and with other OSHA and comparable requirements.

Recent studies have suggested that emissions of certain gases may be contributing to warming of the Earth s atmosphere. In response to these studies, many nations have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention of Climate Change, also known as the Kyoto Protocol. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil and natural gas, and refined petroleum products, are greenhouse gases regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. For example, California adopted the California Global Warming Solutions Act of 2006, which required the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states of the United States could adversely affect our operations and demand for our products. Additionally, the U.S. Supreme Court only recently held in a case, *Massachusetts, et al. v. EPA*, that greenhouse gases fall within the federal Clean Air Act s definition of air pollutant, which could result in the regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our services. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2007. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2008. However, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operation.

Other Regulation of the Oil and Natural Gas Industry

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

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

Drilling and Production. Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;

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the surface use and restoration of properties upon which wells are drilled;

the plugging and abandoning of wells; and

notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or pro-ration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Natural gas regulation. The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The Federal Energy Regulatory Commission s regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

State regulation. The various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

As of December 31, 2007, we had 58 full-time employees, including nine petroleum engineers, six accountants and two landmen, none of whom are subject to collective bargaining agreements. We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, financial and other disciplines as needed. We believe that we have a favorable relationship with our employees.

Offices

We currently lease approximately 32,153 square feet of office space in Midland, Texas at 303 W. Wall Street, Suite 1400, where our principal offices are located. The lease for our Midland office expires in August 2011.

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ITEM 1A. *RISK FACTORS*

Risks Related to our Business

We may not have sufficient available cash to pay the full amount of our current quarterly distribution or any distribution at all following establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient available cash each quarter to pay the full amount of our current quarterly distribution or any distribution at all. The amount of cash we distribute in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than our current quarterly distribution. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserves that our general partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. Further, our debt agreements contain restrictions on our ability to pay distributions. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of oil and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- whether we are able to acquire additional oil and natural gas properties at economically attractive prices;
- whether we are able to continue our development projects at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and development costs, including payments to our general partner;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; and
- the level of our capital expenditures.

If we are not able to acquire additional oil and natural gas reserves on economically acceptable terms, our reserves and production will decline, which would adversely affect our business, results of operations and financial condition and our ability to make cash distributions to our unitholders.

We will be unable to sustain distributions at the current level without making accretive acquisitions or substantial capital expenditures that maintain or grow our asset base. Oil and natural gas reserves are characterized by declining production rates, and our future oil and natural gas reserves and production and, therefore, our cash flow and our ability to make distributions are highly dependent on our success in economically finding or acquiring additional recoverable reserves and efficiently developing and exploiting our current reserves. Further, the rate of estimated decline of our oil and natural gas reserves may increase if our wells do not produce as expected. We may not be able to find, acquire or develop additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Because we distribute all of our available cash to our unitholders, our future growth may be limited.

Since we will distribute all of our available cash as defined in our partnership agreement to our unitholders, our growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. We will depend on financing provided by commercial banks and other lenders and the issuance of debt and equity securities to finance any significant growth or acquisitions. If we are unable to obtain adequate financing from these sources, our ability to grow will be limited.

If commodity prices decline significantly for a prolonged period, we may be forced to reduce our distribution or not be able to pay distributions at all.

A significant decline in oil and natural gas prices over a prolonged period would have a significant impact on the value of our reserves and on our cash flow, which would force us to reduce or suspend our distribution. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the price and quantity of imports of crude oil and natural gas;
- overall domestic and global economic conditions;
- political and economic conditions in other oil and natural gas producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- the impact of the U.S. dollar exchange rates on oil and natural gas prices; and
- the price and availability of alternative fuels.

In the past, the prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue.

If commodity prices decline significantly for a prolonged period, a significant portion of our development projects may become uneconomic, which may adversely affect our ability to make distributions to our unitholders.

Lower oil and natural gas prices may not only decrease our revenues, but also reduce the amount of oil and natural gas that we can produce economically. Furthermore, substantial decreases in oil and natural gas prices as were experienced as recently as 2002, when prices of less than $20.00 per Bbl of oil and $2.00 per Mcf of natural gas were received at the wellhead, would render a significant portion of our development projects uneconomic. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under our credit facility to pay distributions to our unitholders.

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

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our credit facility has substantial restrictions and financial covenants, and our borrowing base is subject to redetermination by our lenders which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We will depend on our revolving credit facility for future capital needs. Our revolving credit facility restricts, among other things, our ability to incur debt and pay distributions, and requires us to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under our revolving credit facility could result in a default under our revolving credit facility. A default under our revolving credit facility could cause all of our existing indebtedness to be immediately due and payable. Additionally, our revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion.

We are prohibited from borrowing under our revolving credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our revolving credit facility reaches or exceeds 90% of the borrowing base, which is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices at such time. Any time our borrowings exceed 90% of the then specified borrowing base, our ability to pay distributions to our unitholders in any such quarter is solely dependent on our ability to generate sufficient cash from our operations.

Outstanding borrowings in excess of the borrowing base must be repaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties used to determine the borrowing base, we must pledge other oil and natural gas properties as additional collateral. We may not have the financial resources in the future to make any mandatory principal prepayments required under our revolving credit facility.

The occurrence of an event of default or a negative redetermination of our borrowing base could adversely affect our business, results of operations, financial condition and our ability to make distributions to our unitholders.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Financing Activities.

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas we produce.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our development projects require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

We make and expect to continue to make substantial capital expenditures in our business for the development, development, production and acquisition of oil and natural gas reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

our proved reserves;

the level of oil and natural gas we are able to produce from existing wells;

the prices at which our oil and natural gas are sold; and

our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil and/or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our credit facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We do not control all of our operations and development projects and failure of an operator of wells in which we own partial interests to adequately perform could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Much of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas wells.

If we do not operate wells in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The success and timing of our development projects on properties operated by others is outside of our control.

The failure of an operator of wells in which we own partial interests to adequately perform operations, or an operator s breach of the applicable agreements, could reduce our production and revenues and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Shortages of drilling rigs, equipment and crews could delay our operations, adversely affect our ability to increase our reserves and production and reduce our cash available for distribution to our unitholders.

Higher oil and natural gas prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could adversely affect our ability to increase our reserves and production and reduce our revenues and cash available for distribution to our unitholders.

Increases in the cost of drilling rigs, service rigs, pumping services and other costs in drilling and completing wells could reduce the viability of certain of our development projects.

The rig count and the cost of rigs and oil field services necessary to implement our development projects have risen significantly with the increases in oil and natural gas prices. Increased capital requirements for our projects will result in higher reserve replacement costs which could reduce cash available for distribution. Higher project costs could cause certain of our projects to become uneconomic and therefore not to be implemented, reducing our production and cash available for distribution.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable.

In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions;
- title disputes;
- pipeline ruptures or spills;
- collapses of wellbore, casing or other tubulars;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Increases in interest rates could adversely affect our business, results of operations, cash flows from operations and financial condition.

Since all of the indebtedness outstanding under our credit facility is at variable interest rates, we have significant exposure to increases in interest rates. As a result, our business, results of operations and cash flows may be adversely affected by significant increases in interest rates. Further, an increase in interest rates may cause a corresponding decline in demand for equity investments, in particular for yield-based equity investments such as our units. Any reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units to decline.

We may have assumed unknown liabilities in connection with the formation transactions and our subsequent acquisitions.

As part of the formation transactions and subsequent acquisitions, our properties may be subject to existing liabilities, some of which may have been unknown at the closing of such transactions. Unknown liabilities might include liabilities for cleanup or remediation of undisclosed or unknown environmental conditions, claims of vendors or other persons (that had not been asserted or threatened prior to the closing of such transactions), tax liabilities and accrued but unpaid liabilities incurred in the ordinary course of business.

Properties that we buy may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

One of our growth strategies is to acquire additional oil and natural gas reserves. However, our reviews of acquired properties are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume environmental and other risks and liabilities in connection with acquired properties.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our commodity derivative activities could result in cash losses, could reduce our cash available for distributions and may limit potential gains.

We have entered into, and we may in the future enter into, oil and natural gas derivative contracts intended to offset the effects of price volatility related to a significant portion of our oil and natural gas production. Many derivative instruments that we employ require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices.

If our actual production and sales for any period are less than our expected production covered by derivative contracts and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our derivative contracts without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. Lastly, an attendant risk exists in derivative activities that the counterparty in any derivative transaction cannot or will not perform under the instrument and that we will not realize the benefit of the derivative. Under our credit facility, we are prohibited from entering into derivative contracts covering all of our production, and we therefore retain the risk of a price decrease on our volumes not subject to derivative contracts.

The inability of one or more of our customers to meet their obligations may adversely affect our financial condition and results of operations.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil and natural gas hedging arrangements expose us to credit risk in the event of nonperformance by counterparties.

We depend on a limited number of key personnel who would be difficult to replace.

Our operations are dependent on the continued efforts of our executive officers, senior management and key employees. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy.

We may be unable to compete effectively with larger companies, which could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration and development activities during periods of low oil and natural gas market prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

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

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. All such costs may have a negative effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our ability to make cash distributions to our unitholders could be adversely affected.

Risks Related to Our Limited Partnership Structure

Units eligible for future sale may have adverse effects on our unit price and the liquidity of the market for our units.

We cannot predict the effect of future sales of our units, or the availability of units for future sales, on the market price of or the liquidity of the market for our units. Sales of substantial amounts of units, or the perception that such sales could occur, could adversely affect the prevailing market price of our units. Such sales, or the possibility of such sales, could also make it difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. Factors affecting the likely volume of future sales of our units, and the possible consequences of such sales, include the following:

All of our units issued in our private equity offerings were restricted securities within the meaning of Rule 144 under the Securities Act. As more of our units become eligible for sale under Rule 144, the volume of sales of our units may increase, which could reduce the market price of our units.

The Founding Investors and their affiliates, including members of our management, own approximately 43% of our outstanding units. We granted the Founding Investors certain registration rights to have their units registered under the Securities Act. Upon registration, these units will be eligible for sale into the market. Because of the substantial size of the Founding Investors holdings, the sale of a significant portion of these units, or a perception in the market that such a sale is likely, could have a significant impact on the market price of our units.

We granted purchasers in our private equity offerings certain registration rights to have the resale of their units registered under the Securities Act. If purchasers in our private equity offerings were to resell a substantial portion of their units, it could reduce the market price of our outstanding units.

Our Founding Investors, including members of our management, own a 43% limited partner interest in us and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner has conflicts of interest and limited fiduciary duties, which may permit it to favor its own interests to the detriment of our unitholders.

Our Founding Investors, including members of our management, own a 43% limited partner interest in us and therefore have the ability to effectively control the election of the entire board of directors of our general partner.

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Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners, our Founding Investors and their affiliates. Conflicts of interest may arise between our Founding Investors and their affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our Founding Investors or their affiliates, other than our executive officers, to pursue a business strategy that favors us;

- our general partner is allowed to take into account the interests of parties other than us, such as our Founding Investors, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

- our Founding Investors and their affiliates (other than our executive officers and their affiliates) may engage in competition with us;

- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing units, unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to our unitholders;

- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or a growth capital expenditure, which does not. Such determination can affect the amount of cash that is distributed to our unitholders;

- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

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

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

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

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

Even if unitholders are dissatisfied they cannot remove our general partner without the consent of unitholders owning at least 662/3% of our units, including units owned by our general partner and its affiliates.

Currently, the unitholders are unable to remove our general partner without its consent because our general partner s affiliates own sufficient units to be able to prevent our general partner s removal. The vote of the holders of at least

662/3% of all outstanding units voting together as a single class is required to remove the general partner. Affiliates of our general partner, including members of our management, own 43% of our units.

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Our partnership agreement restricts the voting rights of those unitholders owning 20% or more of our units.

Unitholders voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

Our Founding Investors and their affiliates (other than our executive officers and their affiliates) may compete directly with us.

Our Founding Investors and their affiliates, other than our general partner and our executive officers and their affiliates, are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, our Founding Investors or their affiliates, other than our general partner and our executive officers and their affiliates, may acquire, develop and operate oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to acquire, develop or operate those assets.

Cost reimbursements due our general partner and its affiliates will reduce our cash available for distribution to our unitholders.

Prior to making any distribution on our outstanding units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. Any such reimbursement will be determined by our general partner in its sole discretion. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. The reimbursement of expenses of our general partner and its affiliates could adversely affect our ability to pay cash distributions to our unitholders.

Our partnership agreement limits our general partner s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;

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

- provides that our general partner is entitled to make other decisions in good faith if it believes that the decision is in our best interest;

- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be fair and reasonable to us, as determined by our general partner in good faith, and that, in determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

provides that our general partner and its officers and directors will not be liable for monetary damages to us, our unitholders or assignees for any acts or omissions unless there has been a final and non-appealable

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judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

Our partnership agreement permits our general partner to redeem any partnership interests held by a limited partner who is a non-citizen assignee.

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, our general partner may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, our general partner may elect to treat the limited partner as a non-citizen assignee. A non-citizen assignee is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

We may issue an unlimited number of additional units without the approval of our unitholders, which would dilute their existing ownership interest in us.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units. The issuance by us of additional units or other equity securities of equal or senior rank will have the following effects:

our unitholders proportionate ownership interests in us will decrease;

the amount of cash available for distribution on each unit may decrease;

the risk that a shortfall in the payment of our current quarterly distribution will increase;

the relative voting strength of each previously outstanding unit may be diminished; and

the market price of the units may decline.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. In some states, including Delaware, a limited partner is only liable if he participates in the control of the business of the partnership. These statutes generally do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. Our unitholders could, however, be liable for any and all of our obligations as if our unitholders were a general partner if:

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

our unitholders right to act with other unitholders to take other actions under our partnership agreement that constitute control of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

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

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by states and localities. If the IRS were to treat us as a corporation or if we were to become subject to a material amount of additional entity-level taxation for state or local tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter 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, which currently has a top marginal rate of 35%, and would likely pay state and local income tax at the corporate tax rate of the various states and localities imposing a corporate income tax. Distributions to our unitholders would generally be taxed again as corporate distributions, 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 to pay distributions to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders 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 income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are subject to a new entity-level state tax on the portion of our income that is generated in Texas beginning for tax reports due on or after January 1, 2008. Specifically, the Texas margin tax is imposed at a maximum effective rate of 0.7% of our gross income that is apportioned to Texas. If any additional states were to impose a tax upon us as an entity, the cash available for distribution to our unitholders would be reduced.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, or Qualifying Income Exception, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) of the Internal Revenue Code. Legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay 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. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

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.

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. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. 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.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our units, and the costs of any contest will reduce our cash available for distribution to our unitholders.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel s conclusions or the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may disagree with some or all of our counsel s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, the costs of any contest with the IRS will result in a reduction in cash available to pay distributions to our unitholders and thus will be borne indirectly by our unitholders.

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

Investment in our 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.

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

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

We will treat each purchaser of our units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of units, we will adopt depletion, depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. Our counsel is unable to opine as to the validity of such filing positions. 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 units and could have a negative impact on the value of our units or result in audits of and adjustments to our unitholders tax returns.

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 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, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where our units are loaned to a short seller to cover a short sale of our units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local income 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 they 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 various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently do business and own assets in Texas, New Mexico, Oklahoma, Alabama, Mississippi, Wyoming, North Dakota, Colorado and Arkansas. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all 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 our units.

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

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 interests in our capital and profits within a twelve-month period. Our 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.

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ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 2. *PROPERTIES*

As of December 31, 2007 we owned interests in producing oil and natural gas properties in 214 fields in the Permian Basin, Texas Panhandle and Anadarko Basin of Oklahoma, operated 1,547 gross productive wells and owned non-operated interests in 2,207 gross productive wells. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2007. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves. For a definition of standardized measure please see the glossary of terms at the beginning of this annual report on Form 10-K.

	As of December 31, 2007				
	Proved Reserves			Standardized Measure	
Field	**MMBoe**	**R/P(a)**	**% Oil and NGL s**	**Amount ($ in Millions)**	**% of Total**
Texas Panhandle Fields	4.6	19	81%	$ 86.9	12.6%
Spraberry	3.6	14	67	84.7	12.3
East Binger	3.4	13	83	77.0	11.1
Denton	2.2	16	87	48.1	6.9
Farmer	1.8	19	66	30.9	4.5
Langlie Mattix	1.3	17	85	29.2	4.2
Howard Glasscock/Iatan/Iatan East Howard	1.3	17	99	26.7	3.9
Total Top 7 fields	18.2	16	79%	$ 383.5	55.5%
All others	13.9	13	66	307.0	44.5
Total	32.1	14	74%	$ 690.5	100.0%

(a) Reserves as of December 31, 2007 divided by annual production volumes.

Summary of Oil and Natural Gas Properties and Projects

Our most significant fields are the Texas Panhandle, Spraberry, East Binger, Denton, Farmer, Langlie Mattix and Howard Glasscock/Iatan/Iatan East Howard. As of December 31, 2007 these seven fields accounted for approximately 56.7% of our total estimated proved reserves.

Texas Panhandle Fields. In October of 2007, Legacy Reserves acquired producing properties in the Texas Panhandle fields located in Carson, Gray, Hartley, Hutchinson, Moore, and Potter Counties, Texas, in two acquisitions. The fields are produced from multiple formations of Permian age which primarily include the Granite Wash, Brown Dolomite, and Red Cave formations from 2,500 to 4,000 feet. Legacy operates 277 wells (263 producing, 14 injecting) in the Texas Panhandle fields with working interests ranging from 81.3% to 100% and net revenue interests ranging from 69.3% to 100.0%. We also own another 271 wells (268 producing, 3 injecting) with a 3.8% average non-operated working interest. As of December 31, 2007, our properties in the Texas Panhandle fields contained 4.6 MMBoe (81% liquids) of net proved reserves with a standardized measure of $86.9 million. The average net daily production from these fields was 1,086 Boe/d in December 2007. The estimated reserve life (R/P) for these fields is 19 years.

Spraberry Field. The Spraberry field is located in Midland, Martin, Reagan and Upton counties, Texas. This field produces from Spraberry and Wolfcamp age formations from 5,000 to 10,200 feet. We operate 127 active wells in this field with working interests ranging from 4.0% to 100% and net revenue interests ranging from 4.0% to 90.8%. We have a 1.3% overriding royalty interest in one non-operated unit in the Spraberry field. We also have three lease line wells outside the non-operated unit with a working interest of 12.5% and a net revenue interest of 9.4%. As of December 31, 2007, our properties in the Spraberry field contained 3.6 MMBoe (67% liquids) of net proved reserves with a standardized measure of $84.7 million. The average net daily production from this field was 586 Boe/d for the fourth quarter of 2007. The estimated reserve life for this field is 14 years.

Six operated and three non-operated wells were drilled on Legacy Reserves properties in the Spraberry Field in 2007. We have identified eleven more proved undeveloped projects and eight behind-pipe or proved developed non-producing (PDNP) re-completion projects in this field.

East Binger Field. In April 2007, Legacy Reserves acquired producing properties in the East Binger field located in Caddo County, Oklahoma. This field which is on the Northeastern shelf of the Anadarko Basin was discovered in 1935 and through December 31, 2007, our properties in this field had gross cumulative production of 22.0 MMBbls of oil and 130.5 Bcf of natural gas. The Marchand Sand, at depths of 9,700 to 10,100 feet, is the primary reservoir in the East Binger Field. The East Binger Unit, the major property in the field, is an active miscible nitrogen injection project and is operated by Binger Operations, LLC (BOL) of which Legacy owns 50%. BOL operates 91 wells in the East Binger field and Legacy Reserves owns a working interest of 54.5% and net revenue interest of 45.8% in the East Binger Unit. As of December 31, 2007, our properties in the East Binger field contained 3.4 MMBoe (83% liquids) of net proved reserves with a standardized measure of $77.0 million. The average net daily production from this field was 812 Boe/d for the fourth quarter of 2007. The estimated reserve life (R/P) for the field is 13 years.

Two infill wells were drilled in the East Binger Unit in 2007 and we have nine more proved undeveloped projects identified in this field.

Denton Field. The Denton field is an oil and natural gas field located in Lea County, New Mexico. The Devonian Formation at depths of 11,000 to 12,700 feet is the primary reservoir in the Denton field. Additional production has been developed in the Wolfcamp Formation at depths of 8,900 to 9,600 feet. We operate 17 wells in the Denton field with working interests ranging from 86% to 100% and net revenue interests ranging from 75.1%to 87.5%. We also own another 6 producing wells with a 15.0% average non-operated working interest. As of December 31, 2007, our properties in the Denton field contained 2.2 MMBoe (87% liquids) of net proved reserves with a standardized measure of $48.1 million. The average net daily production from this field was 390 Boe/d for the fourth quarter of 2007. The estimated reserve life (R/P) for the field is 16 years.

Farmer Field. The Farmer field is an oil and natural gas field located in Crockett and Reagan counties, Texas. The San Andres Formation at depths of 2,100 to 2,600 feet is the primary reservoir in the Farmer field. We operate 156 wells (148 producing, 8 injecting) in the Farmer field with a 100.0% average working interest and a net revenue interest ranging from 80.8% to 87.5%. As of December 31, 2007, our properties in the Farmer field contained 1.8 MMBoe (66% liquids) of net proved reserves with a standardized measure of $30.9 million. The average net daily production from this field was 275 Boe/d for the fourth quarter of 2007. The estimated reserve life (R/P) for the field is 19 years.

The Farmer field has been developed using 20-acre spacing with the exception of a pilot 10-acre spacing area that includes eleven 10-acre wells. We currently have 33 10-acre proved undeveloped locations in this field and an additional 84 unproved 10-acre locations.

Langlie Mattix Field. The Langlie Mattix field is an oil and natural gas field located in Lea County, New Mexico. The Queen Formation at depths of 3,400 to 3,800 feet is the primary reservoir in the Langlie Mattix field. We operate 104 wells (76 producing, 28 injecting) in the Langlie Mattix Penrose Sand Unit, a subdivision of the Langlie Mattix Field, with a 51.7% average working interest and a 44.7% average net revenue interest. We also operate two other properties with 100% and 82.4% working interests and 82.0% and 67.4% net revenue interests. As of December 31, 2007, our properties in the Langlie Mattix field contained 1.3 MMBoe (85% liquids) of net proved reserves with a standardized measure of $29.2 million. The average net daily production from this field was 218 Boe/d for the fourth quarter of 2007. The estimated reserve life (R/P) for the field is 17 years.

The Langlie Mattix Penrose Sand Unit was drilled in the late 1930s and early 1940s on 40-acre spacing. Waterflooding commenced in 1958. Prior to 2007 there had been 14 20-acre infill wells drilled on the Unit; five drilled in 1983, three drilled in 1992, and six drilled in 2004. All three 20-acre infill programs were successful. We drilled twelve 20-acre infill wells in 2007 and have 23 more proved undeveloped locations and an additional 55 unproved 20-acre locations.

Howard Glasscock, Iatan and Iatan East Howard Fields. The Howard Glasscock, Iatan and Iatan East Howard fields adjoin one another and are located in Howard and Mitchell counties, Texas. These fields produce from multiple formations of Permian age which primarily include the San Andres, Yates, Seven Rivers, Queen, Clearfork and Glorieta Formations from 1,000 to 3,700 feet as well as the Wolfcamp and Canyon Formations from 5,100 to 7,400 feet. We operate 125 wells (115 producing, 10 injecting) in these fields with working interests ranging from 62.5% to 100.0% and net revenue interests ranging from 47.3% to 90.0%. As of December 31, 2007, our properties in the Howard Glasscock, Iatan and Iatan East Howard fields contained 1.3 MMBoe (99% liquids) of net proved reserves with a standardized measure of $26.7 million. The average net daily production from these fields was 208 Boe/d for the fourth quarter of 2007. The estimated reserve life (R/P) for these fields is 17 years.

Oil and Natural Gas Data

Proved Reserves

The following table sets forth a summary of information related to our estimated net proved reserves as of the dates indicated based on reserve reports prepared by LaRoche Petroleum Consultants, Ltd. The estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency. Standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31,		
	2005(a)	**2006**	**2007**
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	8.1	13.4	19.6
Natural Gas Liquids (MMBbls)			4.0
Natural Gas (Bcf)	24.5	32.5	50.9
Total (MMBoe)	12.2	18.8	32.1
Proved developed reserves (MMBoe)	9.8	15.8	29.0
Proved undeveloped reserves (MMBoe)	2.4	3.0	3.1
Proved developed reserves as a percentage of total proved reserves	80%	84%	90%
Standardized measure (in millions)(b)	$ 192.0	$ 240.6	$ 690.5
Oil and Natural Gas Prices (c)			
Oil NYMEX WTI per Bbl	$ 57.64	$ 56.73	$ 91.96
Natural gas NYMEX Henry Hub per MMBtu	$ 8.82	$ 5.82	$ 6.39

(a) Includes 3.2 MMBbls of oil, 13.0 Bcf of natural gas and $93.0 million of standardized measure held by MBN Properties LP of which 1.7 MMBbls of oil, 7.0 Bcf of natural gas and $50.2 million of standardized measure was owned by the non-controlling interest.

(b) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general administrative expenses and debt service or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provision for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions. For a description of our derivative transactions, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow from Operating Activities.

(c) Oil and natural gas prices as of each date are based on NYMEX prices per Bbl of oil and per MMBtu of natural gas at such date, with these representative prices adjusted by field to arrive at the appropriate net price.

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

The data in the above table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. Please read Risk Factors Our estimated reserves are based on many assumptions that may prove inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Standardized measure amounts shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

From time to time, we engage LaRoche Petroleum Consultants, Ltd. to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither LaRoche Petroleum Consultants, Ltd. nor any of its employees has any interest in those properties and the compensation for these engagements is not contingent on their estimates of reserves and future net revenues for the subject properties. During 2006 and 2007, we paid LaRoche Petroleum Consultants, Ltd. approximately $246,992 and $143,900, respectively, for such reserve and economic evaluations.

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Production and Price History

The following table sets forth a summary of unaudited information with respect to our production and sales of oil and natural gas for the periods indicated, including the historical data of Legacy Reserves LP (formerly the Moriah Group) as of December 31, 2005, 2006 and 2007. The 2006 data reflects Legacy s purchase of the oil and natural gas properties acquired in the formation transactions and the South Justis, Farmer Field and Kinder Morgan acquisitions. The 2007 data reflects Legacy s purchase of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisitions:

	Year Ended December 31,		
	2005(a)	**2006(b)**	**2007(c)**
Production:			
Oil (MBbl)	354	749	1,179
Natural gas liquids (Mgal)			5,295
Gas (MMcf)	1,027	2,200	3,052
Total (MBOE)	525	1,116	1,814
Average daily production (BOE per day)	1,438	3,058	4,970
Average sales price per unit (excluding swaps):			
Oil (per Bbl)	$ 51.48	$ 60.55	$ 70.65
NGL (per Gal)	$	$	$ 1.42
Gas (per Mcf)	$ 7.13	$ 6.57	$ 7.02
Combined (per BOE)	$ 48.65	$ 53.58	$ 61.87
Average sales price per unit (including realized swap gains/losses)(f):			
Oil (per Bbl)	$ 41.51(d)	$ 51.65(e)	$ 67.58
NGL (per Gal)	$	$	$ 1.30
Gas (per Mcf)	$ 7.13	$ 9.48	$ 8.48
Combined (per BOE)	$ 41.93(d)	$ 53.35(e)	$ 61.99
Average unit costs per BOE:			
Production costs, excluding production and other taxes	$ 12.14	$ 14.28	$ 14.96
Production and other taxes	$ 3.12	$ 3.36	$ 4.35
General and administrative	$ 2.58	$ 3.31	$ 4.63
Depletion, depreciation and amortization	$ 4.36	$ 16.48	$ 15.66

(a) Reflects the production and operating results of the PITCO properties from their acquisition on September 14, 2005.

(b) Reflects the production and operating results of the oil and natural gas properties acquired in the March 15, 2006 formation transactions and the South Justis, Farmer Field and Kinder Morgan acquisitions from the closing dates of such acquisitions through December 31, 2006.

(c) Reflects the production and operating results of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions from the closing dates of such acquisitions through December 31, 2007.

(d) Includes the effects of approximately $2.0 million of derivative premiums for the year ended December 31, 2005 to cancel and reset 2006 oil swaps from $51.31 to $59.38 per Bbl and approximately $0.8 million of premiums paid on July 22, 2005 for an option to enter into a $55.00 per Bbl oil swap related to the PITCO acquisition that was not exercised.

(e) Includes the effect of approximately $4.0 million of derivative premiums for the year ended December 31, 2006 to cancel and reset 2007 oil swaps from $60.00 to $65.82 per barrel for 372,000 barrels and for 2008 oil swaps from $60.50 to $66.44 per barrel for 348,000 barrels, which reflected the prevailing oil swap market at the time of the reset.

(f) Includes only the realized gains (losses) from Legacy s oil and natural gas swaps.

Productive Wells

The following table sets forth information at December 31, 2007 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Oil		Natural Gas	
	Gross	**Net**	**Gross**	**Net**
Operated	1,184	910.07	110	103.42
Non-operated	1,298	89.70	411	41.12
Total	2,482	999.77	521	144.54

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2007 relating to our leasehold acreage.

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross(c)	**Net(d)**	**Gross(c)**	**Net(d)**
Total	351,618	96,605	480	226

(a) Developed acres are acres spaced or assigned to productive wells or wells capable of production.

(b) Undeveloped acres are acres which are not held by commercially producing wells, regardless of whether such acreage contains proved reserves. All of our proved undeveloped locations are located on acreage currently held by production.

(c) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.

(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activity

The following table sets forth information, on a combined basis, with respect to wells completed by Legacy, the Moriah Group, Brothers Group, H2K, and the charitable foundations, during the years ended December 31, 2005, 2006 and 2007. The drilling activities associated with the PITCO properties are included for all periods subsequent to the acquisition date of September 14, 2005. The drilling activities associated with the properties acquired in the Farmer Field acquisition (June 29, 2006), the South Justis acquisition (June 29, 2006) and the Kinder Morgan acquisition (July 31, 2006) are included for all periods subsequent to those acquisition dates. The drilling activities associated with the properties acquired in the Binger acquisition (April 16, 2007), the Ameristate acquisition (May 1, 2007), the TSF acquisition (May 25, 2007), the Raven Shenandoah acquisition (May 31, 2007), the Raven OBO acquisition (August 3, 2007), the TOC acquisition (October 1, 2007) and the Summit acquisition (October 1, 2007) are included for all periods subsequent to those acquisition dates. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil and natural gas, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,		
	2005	**2006**	**2007**
Gross:			
Development			
Productive	12	14	29
Dry		2	
Total	12	16	29
Exploratory			
Productive			
Dry	1		
Total	1		
Net:			
Development			
Productive	1.6	6.2	13.0
Dry		1.3	
Total	1.6	7.5	13.0
Exploratory			
Productive			
Dry	0.1		
Total	0.1		

Summary of Development Projects

We are currently pursuing an active development strategy. We estimate that our capital expenditures for the year ending December 31, 2008 will be approximately $18.2 million for development drilling, re-completions and re-fracture stimulation and other development related projects to implement this strategy. We intend to drill 24 gross (17.3 net) development wells and execute 12 gross (5.8 net) re-completions and re-fracture simulations projects. All of these development projects are located in the Permian Basin and the East Binger field in Oklahoma.

Operations

General

We operate approximately 61% of our net daily production of oil and natural gas. We design and manage the development, re-completion or work-over for all of the wells we operate and supervise operation and maintenance activities. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate except for two single pole pulling units used for shallow well work in the Panhandle fields. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ drilling, production, and reservoir engineers, geologists and other specialists who have worked and will work to improve production rates, increase reserves, and lower the cost of operating our oil and natural gas properties. We charge the non-operating partners an operating fee for operating the wells, typically on a fee per well operated basis. Our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any well drilled on the lease premises. In the Permian Basin this amount generally ranges from 12.5% to 33.7% resulting in a 87.5% to 66.3% net revenue interest to us. Most of our leases are held by production and do not require lease rental payments.

South Justis Unit Operating Agreement

In connection with our acquisition of the South Justis Unit from Henry Holding LP on June 29, 2006, we became the successor in interest to Henry Holding LP as unit operator under the Unit Operating Agreement. As unit operator, we are entitled to receive from the other working interest owners a per well operating fee which we expect to be an aggregate of $1.7 million annually and is subject to an annual cost escalator. Under the terms of the Unit Agreement, we may be removed as unit operator upon default or failure to perform our duties by a vote of two or more working interest owners representing at least 80% of the working interest other than the interest held by us. In the event that we transfer our working interest ownership, we will be removed as unit operator.

Derivative Activity

We enter into derivative transactions with unaffiliated third parties with respect to oil and natural gas prices to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas prices. All of our derivative transactions in place are NYMEX financial swaps, which do not require option premiums. Our derivatives either swap floating prices for fixed prices indexed on NYMEX for oil, NGL and natural gas or swap the NYMEX index price to an index that reflects a geographical area of production, in our case, the Waha natural gas and ANR-Oklahoma natural gas indices. We enter into derivative transactions with respect to LIBOR interest rates to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in LIBOR interest rates. All of our interest rate derivative transactions are LIBOR interest rate swaps, which do not require option premiums. Our derivatives swap floating LIBOR rates for fixed rates. For a more detailed discussion of our derivative activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow from Operations and Quantitative and Qualitative Disclosures About Market Risk.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title opinions have been obtained on a significant portion of our properties.

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this document.

ITEM 3. ***LEGAL PROCEEDINGS***

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

ITEM 4. ***SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS***

None.

PART II

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

Our units, which were first offered and sold to the public on January 12, 2007, are listed on the NASDAQ Global Select Market under the symbol LGCY . As of March 14, 2008, there were 29,670,887 units outstanding, held by approximately 73 holders of record, including units held by our Founding Investors.

The following table presents the high and low sales prices for our units during the periods indicated (as reported on the NASDAQ Global Select Market) and the amount of the quarterly cash distributions we paid on each of our units with respect to such periods.

2007	**Price Ranges(a) High**	**Low**	**Cash Distribution per Unit**
First Quarter	$ 28.19	$ 18.90	$ 0.4100(b)
Second Quarter	$ 30.42	$ 25.14	$ 0.4200(c)
Third Quarter	$ 27.61	$ 18.50	$ 0.4300(d)
Fourth Quarter	$ 24.57	$ 20.15	$ 0.4500

2006	**Cash Distribution per Unit**
Period from March 15, 2006 to March 31, 2006	$ 0.0774(e)(f)
Second Quarter	$ 0.4100(g)
Third Quarter	$ 0.4100(g)
Fourth Quarter	$ 0.4100(h)

(a) Our units were not traded on an established public trading market prior to our initial public offering in January 2007.

(b)

We paid total cash distributions to our general partner with respect to its approximately 0.1% general partner interest of $7,508.

(c) We paid total cash distributions to our general partner with respect to its approximately 0.1% general partner interest of $7,691.

(d) We paid total cash distributions to our general partner with respect to its approximately 0.1% general partner interest of $7,874.

(e) Reflects a pro-rated distribution for the period from March 15, 2006 through March 31, 2006.

(f) We paid total cash distributions to our general partner with respect to its approximately 0.1% general partner interest of $1,417.

(g) We paid total cash distributions to our general partner with respect to its approximately 0.1% general partner interest of $7,508.

(h) The record date of our distribution attributable to the fourth quarter of 2006 was January 10, 2007 and preceeded the closing of our initial public offering. Accordingly, unitholders of units issued in our initial public offering were not entitled to receive a distribution attributable to the fourth quarter of 2006 on such units.

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Distribution Policy

We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner. We refer to this cash as available cash, which is defined in our partnership agreement. We currently pay quarterly cash distributions of $0.45 per unit.

Recent Sales of Unregistered Securities

In October 2005, in connection with the formation of Legacy Reserves LP, we issued to Moriah Resources, Ltd. the 99.9% limited partner interest in Legacy Reserves LP for $999. The issuance was exempt from registration under Section 4(2) of the Securities Act because the transaction did not involve a public offering.

In connection with our formation transactions on March 15, 2006, we issued units to our Founding Investors contributing oil and natural gas properties and related assets to us. The issuances of the units described below was exempt from registration under Section 4(2) of the Securities Act because the issuances did not involve a public offering. The following table summarizes the issuance of our units in the formation transactions:

	Units
Moriah Group:	
Moriah Properties, Ltd.	7,334,070
DAB Resources, Ltd.	859,703
Brothers Group:	
Brothers Production Properties, Ltd.	4,968,945
Brothers Production Company , Inc.	264,306
Brothers Operating Company, Inc.	52,861
J&W McGraw Properties, Ltd.	914,246
MBN Properties LP	3,162,438
H2K Holdings, Ltd.	83,499

On March 15, 2006, we issued an aggregate of 52,616 restricted units to certain members of management pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuances of these units were exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On March 15, 2006, we issued 5,000,000 units in a private offering for an aggregate consideration of $85 million before the initial purchaser s discount, placement agent s fees and expenses to qualified institutional investors and accredited investors in transactions exempt from registration under Section 4(2) of the Securities Act. We paid Friedman, Billings, Ramsey & Co., Inc., who acted as placement agent and initial purchaser in this transaction, $5.95 million in initial purchaser s discount and placement agent s fees.

On May 1, 2006, we issued 8,750 units in the aggregate to certain of the directors of our general partner pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuances of these units were exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On May 5, 2006, we issued 12,500 restricted units to an employee pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these units was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On June 29, 2006, and November 10, 2006 we issued 138,000 units and 8,415 units, respectively, to Henry Holding LP as partial consideration for our acquisition of oil and natural gas producing properties located in Lea County New Mexico and contract operating rights for total consideration of approximately $13.4 million cash and 146,415 units. The issuances of these units were exempt from registration under Section 4(2) of the Securities Act because the issuances did not involve a public offering.

On July 17, 2006, we issued options to purchase 251,000 units, at an exercise price of $17.00, to employees and officers pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options were exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On September 15, 2006, we issued options to purchase 10,000 units, at an exercise price of $17.00, to an employee pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On October 10, 2006 we issued options to purchase 12,000 units, at an exercise price of $17.25, to employees pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On January 11, 2007 we issued options to purchase 9,000 units, at an exercise price of $19.00, to employees pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On January 30, 2007, we issued 95,000 units in consideration for our acquisition of producing oil and natural gas properties in West Texas. The issuance of these units was exempt from registration under Section 4(2) of the Securities Act because the issuance did not involve a public offering.

On April 16, 2007, we issued 611,247 units in consideration for our acquisition of producing oil and natural gas properties in the East Binger (Marachand) Unit in Caddo County, Oklahoma. The issuance of these units was exempt from registration under Section 4(2) of the Securities Act because the issuance did not involve a public offering.

On November 8, 2007, we issued 3,642,369 units in a private offering for an aggregate consideration of $74.7 million before placement agent s fees and expenses to qualified institutional investors and accredited investors in transactions exempt from registration under Section 4(2) of the Securities Act. We paid RBC Capital Markets $1.5 million in placement agent s fees.

ITEM 6. *SELECTED FINANCIAL DATA*

We were formed in October 2005. Upon completion of our private equity offering and as a result of the related formation transactions on March 15, 2006, we acquired oil and natural gas properties and business operations from the Founding Investors and the three charitable foundations. Although we were the surviving entity for legal purposes, the formation transactions were treated as a purchase with Moriah Properties, Ltd. and its affiliates, or the Moriah Group, being considered, on a combined basis, as the acquiring entity for accounting purposes. As a result, Legacy Reserves LP (formerly the Moriah Group) applied the purchase method of accounting to the separable assets, and the liabilities of the oil and natural gas properties acquired from the Founding Investors (other than the Moriah Group) and the charitable foundations. Our historical financial statements for periods prior to March 15, 2006 only reflect the accounts of the Moriah Group.

The following table shows selected historical financial and operating data for Legacy Reserves LP for the periods and as of the dates indicated. Through March 15, 2006, Legacy s accompanying consolidated historical financial statements reflect the accounts of the Moriah Group, which includes the accounts of Moriah Resources, Inc. as the general partner of Moriah Properties, Ltd., Moriah Properties, Ltd., the oil and natural gas interests individually owned by Dale A. and Rita Brown until October 1, 2005 when those interests were transferred to DAB Resources, Ltd., DAB Resources, Ltd. and the accounts of MBN Properties LP. The Moriah Group consolidated MBN Properties LP as a variable interest entity with the portion of net income (loss) applicable to the other owners equity interests being eliminated through a non-controlling interest adjustment. Although MBN Management, LLC, the general partner of MBN Properties LP, is also a variable interest entity, it was accounted for by the Moriah Group using the equity method. From March 15, 2006, Legacy s historical financial statements also include the results of operations of the oil and natural gas properties acquired from the other Founding Investors and the charitable foundations.

The selected historical financial data of the Moriah Group for the years ended December 31, 2003, 2004 and 2005 are derived from the audited consolidated financial statements of Legacy.

The operating results of the PITCO properties have been included from their September 14, 2005 acquisition date. The operating results of the Farmer Field, South Justis and Kinder Morgan acquisition properties have been included from their acquisition dates in June and July 2006. The operating results of the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisition properties have been included from their acquisition dates.

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You should read the following selected financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and Legacy s financial statements and related notes included elsewhere in this annual report on Form 10-K.

	Years Ended December 31,				
	2003	2004	2005(a)	2006(b)	2007(c)
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$ 7,919	$ 10,998	$ 18,225	$ 45,351	$ 83,301
Natural gas liquids sales					7,502
Natural gas sales	3,697	3,945	7,318	14,446	21,433
Total Revenues	11,616	14,943	25,543	59,797	112,236
Expenses:					
Oil and natural gas production	3,496	4,345	6,376	15,938	27,129
Production and other taxes	661	928	1,636	3,746	7,889
General and administrative	543	731	1,354	3,691	8,392
Dry hole costs	1,465	1			
Depletion, depreciation, amortization and accretion	766	883	2,291	18,395	28,415
Impairment of long-lived assets	471			16,113	3,204
Loss on disposal of assets			20	42	527
Total expenses	7,402	6,888	11,677	57,925	75,556
Operating income	4,214	8,055	13,866	1,872	36,680
Other income (expense):					
Interest income	56	419	185	130	321
Interest expense	(94)	(213)	(1,584)	(6,645)	(7,118)
Gain on sale of partnership investment		1,292			
Equity in income (loss) of partnerships	311	183	(495)	(318)	77
Realized gain (loss) on oil, NGL and natural gas swaps	(623)	(74)	(3,531)	(262)	211
Unrealized gain (loss) on oil, NGL and natural gas swaps natural gas swaps	340	(559)	(2,628)	9,551	(85,367)
Other	3	92	45	29	(129)
Income (loss) before non-controlling interest and income taxes	4,207	9,195	5,858	4,357	(55,325)
Non-controlling interest			1		
Income before income taxes	4,207	9,195	5,859	4,357	(55,325)
Income taxes					(337)
Income (loss) from continuing operations	$ 4,207	$ 9,195	$ 5,859	$ 4,357	$ (55,662)

Earnings (loss) from continuing operations per unit										
Basic and fully diluted	$	0.44	$	0.97	$	0.62	$	0.26	$	(2.13)
Distributions per unit(d)	$		$		$		$	0.8974	$	1.67

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	Years Ended December 31,				
	2003	2004	2005(a)	2006(b)	2007(c)
	(In thousands)				
Cash Flow Data:					
Net cash provided by operating activities	$ 6,799	$ 8,586	$ 14,409	$ 29,590	$ 57,147
Net cash provided by (used in) investing activities	$ (8,475)	$ 1,023	$ (68,965)	$ (62,505)	$ (196,505)
Net cash provided by (used in) financing activities	$ 1,717	$ (8,958)	$ 55,742	$ 32,022	$ 147,900
Capital expenditures	$ 4,047	$ 3,325	$ 66,915	$ 56,150	$ 196,702

	Historical Year Ended December 31,				
	2003	2004	2005(a)	2006(b)	2007(c)
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$ 117	$ 769	$ 1,955	$ 1,062	$ 9,604
Other current assets	7,826	5,799	6,316	17,159	23,954
Oil and natural gas properties, net of accumulated depletion, depreciation and amortization	9,954	12,224	77,172	247,580	440,180
Other assets	651		1,499	7,567	7,840
Total assets	$ 18,548	$ 18,792	$ 86,942	$ 273,368	$ 481,578
Current liabilities	$ 9,157	$ 4,898	$ 4,562	$ 10,834	$ 43,457
Long term debt			52,473	115,800	110,000
Other long-term liabilities	2,113	1,872	19,998	7,945	72,391
Unitholders equity	7,278	12,022	9,909	138,789	255,730
Total liabilities and unitholders equity	$ 18,548	$ 18,792	$ 86,942	$ 273,368	$ 481,578

(a) Reflects purchase of the PITCO properties on September 14, 2005. Consequently, the operations of the PITCO properties are only included for the period following the date of acquisition.

(b) Reflects Legacy s purchase of the oil and natural gas properties acquired in the March 15, 2006 formation transactions and the South Justis, Farmer Field and Kinder Morgan acquisitions in June and July 2006. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2006.

(c) Reflects Legacy s purchase of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisitions as of the date of their acquisition. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2007.

(d) Amounts not presented for years prior to 2006 since they would not be meaningful.

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

The following discussion and analysis should be read in conjunction with the Selected Historical Consolidated Financial Data and the accompanying financial statements and related notes included elsewhere in annual report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in Risk Factors and Cautionary Note Regarding Forward-Looking Statements, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We were formed in October 2005. Upon completion of our private equity offering and as a result of the related formation transactions on March 15, 2006, we acquired oil and natural gas properties and business operations from our Founding Investors and three charitable foundations (Legacy Formation). Although we were the surviving entity for legal purposes, the formation transactions are treated as a purchase with Moriah Properties, Ltd. and its affiliates, or the Moriah Group, being considered, on a combined basis, as the acquiring entity for accounting purposes. Therefore, the accounts reflected in our historical financial statements prior to March 15, 2006 are those of the Moriah Group.

The Moriah Group owned and operated oil and natural gas producing properties located primarily in the Permian Basin of West Texas and southeast New Mexico. The Moriah Group included the accounts of Moriah Resources, Inc. as the general partner of Moriah Properties, Ltd., the oil and natural gas interests individually owned by Dale A. and Rita Brown until October 1, 2005 when those interests were transferred to DAB Resources, Ltd., DAB Resources, Ltd. and the accounts of MBN Properties LP. The Moriah Group consolidated MBN Properties LP as a variable interest entity with the portion of net income (loss) applicable to the other owners equity interests eliminated through a non-controlling interest adjustment. Although MBN Management, LLC, the general partner of MBN Properties LP, is also a variable interest entity, it was accounted for by the Moriah Group using the equity method.

Because of our rapid growth through acquisitions and development of properties, historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results. Since the PITCO properties were not acquired until September 14, 2005, the results of operations only include the operating results for the PITCO properties from September 14, 2005. The operating results of the properties acquired in the formation transactions are included in the results of operations from March 15, 2006, the operating results of the South Justis Unit properties and the Farmer Field properties acquired on June 29, 2006 have been included from July 1, 2006 and the operating results of the Kinder Morgan properties have been included from August 1, 2006. The operating results of the properties acquired in the Binger Acquisition are included in the results of operations from April 16, 2007, the operating results of the Ameristate Acquisition have been included from May 1, 2007, the operating results of the TSF Acquisition have been included from May 25, 2007, the operating results of the Raven Shenandoah Acquisition have been included from May 31, 2007, the operating results of the Raven OBO Acquisition have been included from August 3, 2007 and the operating results from the TOC and Summit Acquisitions have been included from October 1, 2007.

Acquisitions have been financed with a combination of proceeds from bank borrowings and issuances of units and cash flow from operations. Post-acquisition activities are focused on evaluating and exploiting the acquired properties and evaluating potential add-on acquisitions.

Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future.

Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Higher oil and natural gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services, and have caused increases in the costs of those goods and services. To date, the higher sales prices have more than offset the higher drilling and operating costs. Given the inherent volatility of oil and natural gas prices, which are influenced by many factors beyond our control, we plan our activities and budget based on sales price assumptions which historically have been lower than the average sales prices received. We focus our efforts on increasing oil and natural gas production and reserves while controlling costs at a level that is appropriate for long-term operations.

We face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. We attempt to overcome this natural decline by utilizing multiple types of recovery techniques such as secondary (water-flood) and tertiary (CO_2) recovery methods to re-pressure the reservoir and recover additional oil, drilling to find additional reserves, re-stimulating existing wells and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on adding reserves through acquisitions and development projects. Our ability to add reserves through acquisitions and development projects is dependent upon many factors including our ability to raise capital, obtain regulatory approvals and contract drilling rigs and personnel.

Our revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. As set forth under Cash Flow from Operations below, we have hedged a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our capital investment programs and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact, if any, on any re-determination to our borrowing base under our credit facility.

Legacy does not specifically designate derivative instruments as cash flow hedges; therefore, the mark-to-market adjustment reflecting the unrealized gain or loss associated with these instruments is recorded in current earnings.

Production and Operating Costs Reporting

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the optimal level. Accordingly, we continuously monitor our production and operating costs per well to determine if any wells or properties should be shut in, re-completed or sold.

Such costs include, but are not limited to, the cost of electricity to lift produced fluids, chemicals to treat wells, field personnel to monitor the wells, well repair expenses to restore production, well work-over expenses intended to increase production and ad valorem taxes. We incur and separately report severance taxes paid to the states and counties in which our properties are located. These taxes are reported as production taxes and are a percentage of oil and natural gas revenue. Ad valorem taxes are a percentage of property valuation. Gathering and transportation costs are generally borne by the purchasers of our oil and natural gas as the price paid for our products reflects these costs.

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Operating Data

The following table sets forth selected financial and operating data of Legacy for the periods indicated.

	Year Ended December 31,		
	2005(a)	2006(b)	2007(c)
	(In thousands, except per unit data)		
Revenues:			
Oil sales	$ 18,225	$ 45,351	$ 83,301
Natural gas liquid sales			7,502
Natural gas sales	7,318	14,446	21,433
Total revenue	$ 25,543	$ 59,797	$ 112,236
Expenses:			
Oil and natural gas production	$ 6,376	$ 15,938	$ 27,129
Production and other taxes	$ 1,636	$ 3,746	$ 7,889
General and administrative	$ 1,354	$ 3,691	$ 8,392
Depletion, depreciation, amortization and accretion	$ 2,291	$ 18,395	$ 28,415
Realized swap settlements:			
Realized loss on oil swaps	$ (3,531)	$ (6,667)	$ (3,627)
Realized loss on natural gas liquid swaps	$	$	$ (619)
Realized gain on natural gas swaps	$	$ 6,405	$ 4,457
Production:			
Oil barrels	354	749	1,179
Natural gas liquids gallons			5,295
Natural gas Mcf	1,027	2,200	3,052
Total (MBoe)	525	1,116	1,814
Average daily production (Boe/d)	1,438	3,058	4,970
Average sales price per unit:			
Oil price per barrel	$ 51.48	$ 60.55	$ 70.65
Natural gas liquid price per gallon	$	$	$ 1.42
Natural gas price per Mcf	$ 7.13	$ 6.57	$ 7.02
Combined (per Boe)	$ 48.65	$ 53.58	$ 61.87
Average sales price per unit (including realized swap settlements):			
Oil price per barrel	$ 41.51(d)	$ 51.65(e)	$ 67.58
Natural gas liquid price per gallon	$	$	$ 1.30
Natural gas price per Mcf	$ 7.13	$ 9.48	$ 8.48
Combined (per Boe)	$ 41.93(d)	$ 53.35(e)	$ 61.99
NYMEX oil index prices per barrel:			
Beginning of Period	$ 43.45	$ 61.04	$ 61.05
End of Period	$ 61.04	$ 61.05	$ 95.98
NYMEX gas index prices per Mcf:			
Beginning of Period	$ 6.15	$ 11.25	$ 6.30
End of Period	$ 11.25	$ 6.30	$ 7.48
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$ 12.14	$ 14.28	$ 14.96

Production and other taxes	$ 3.12	$ 3.36	$ 4.35
General and administrative	$ 2.58	$ 3.31	$ 4.63
Depletion, depreciation, amortization and accretion	$ 4.36	$ 16.48	$ 15.66

(a) Reflects the production and operating results of the PITCO properties from their acquisition on September 14, 2005.

(b) Reflects the production and operating results of the oil and natural gas properties acquired in the March 15, 2006 formation transactions and the South Justis, Farmer Field and Kinder Morgan Acquisitions from the closing dates of such acquisitions through December 31, 2006.

(c) Reflects the production and operating results of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions from the closing dates of such acquisitions through December 31, 2007.

(d) Includes the effects of approximately $2.0 million of derivative premiums for the year ended December 31, 2005 to cancel and reset 2006 oil swaps from $51.31 to $59.38 per Bbl and approximately $0.8 million of premiums paid on July 22, 2005 for an option to enter into a $55.00 per Bbl oil swap related to the PITCO Acquisition that was not exercised.

(e) Includes the effect of approximately $4.0 million of derivative premiums to cancel and reset 2007 oil swaps from $60.00 to $65.82 per barrel for 372,000 barrels and for 2008 oil swaps from $60.50 to $66.44 per barrel for 348,000 barrels, which reflected the prevailing oil swap market at the time of the reset.

Results of Operations

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Legacy s revenues from the sale of oil were $83.3 million and $45.4 million for the years ended December 31, 2007 and 2006, respectively. Legacy s revenues from the sale of NGL s were $7.5 million for the year ended December 31, 2007. Legacy had no revenues from NGL sales for the year ended December 31, 2006. Legacy s revenues from the sale of natural gas were $21.4 million and $14.4 million for the years ended December 31, 2007 and 2006, respectively. The $37.9 million increase in oil revenues reflects an increase in oil production of 430 MBbls (57%) due primarily to Legacy s purchase of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions while the realized price increased $10.10 per Bbl. The $7.5 million increase in NGL revenues is due to Legacy s purchase of oil and natural gas properties acquired in the Binger, Ameristate, Raven Shenandoah, Raven OBO and TOC Acquisitions. The $7.0 million increase in natural gas revenues reflects an increase in natural gas production of approximately 852 MMcf (39%) due primarily to Legacy s purchase of oil and natural gas properties in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions while the realized price per Mcf increased $0.45 per Mcf.

For the year ended December 31, 2007, Legacy recorded $85.2 million of net losses on oil and natural gas swaps comprised of realized gains of $0.2 million from net cash settlements of oil, NGL and natural gas swap contracts and net unrealized losses of $85.4 million. Legacy had unrealized net losses from its oil swaps because the fixed price of its oil swap contracts were below the NYMEX index prices at December 31, 2007. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close at December 31, 2007 was $95.98 per Bbl, a price which is greater than the average contract prices of Legacy s outstanding oil swap contracts. Legacy had unrealized net losses from its NGL swaps because the fixed price of its NGL swap contracts were below the NYMEX index prices at December 31, 2007. Legacy had unrealized net losses from its natural gas swaps because the fixed prices of its natural gas swap contracts were below the NYMEX index prices at December 31, 2007. As a point of reference, the NYMEX price for natural gas for the near-month close at December 31, 2007 was $7.48 per MMbtu, a price which is greater than the average contract prices of Legacy s outstanding natural gas swap contracts. For the year ended December 31, 2006, Legacy recorded $2.3 million of net losses on oil swaps comprised of a realized loss of $6.7 million from net cash settlements of oil swap contracts and a net unrealized gain of $4.3 million. For the year ended December 31, 2006, Legacy recorded $11.6 million of net gains on gas swaps comprised of a realized gain of $6.4 million from net cash settlements of gas swap contracts and a net unrealized gain of $5.2 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods.

Legacy s oil and natural gas production expenses, excluding production and other taxes, increased to $27.1 million ($14.96 per Boe) for the year ended December 31, 2007, from $15.9 million ($14.28 per Boe) for the year ended December 31, 2006. Production expenses increased primarily because of (i) $2.9 million related to the Binger Acquisition, (ii) $3.4 million related to the Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions and (iii) increased production and increased cost of services and certain operating costs that are directly related to higher commodity prices, particularly the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil.

Legacy s production and other taxes were $7.9 million and $3.7 million for the years ended December 31, 2007 and 2006, respectively. Production and other taxes increased primarily because of (i) approximately $1.0 million of taxes related to the Binger Acquisition, (ii) $1.0 million of taxes related to the Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions and (iii) higher commodity prices in the 2007 period.

Legacy s general and administrative expenses were $8.4 million and $3.7 million for the years ended December 31, 2007 and 2006, respectively. General and administrative expenses increased approximately $4.7 million between periods primarily due to (i) increased employee costs related to business expansion, (ii) $1.4 million of costs incurred in connection with awards granted under the LTIP due to a $1.1 million non-cash expense related to the change in estimated fair value of the unit-based compensation liability related to unit options, unit grants, phantom unit grants and unit appreciation rights and $0.3 million of cash payments to employees exercising unit options and (iii) approximately $0.5 million of costs incurred in connection with the preparation of the 2006 federal income tax return and related form K-1 s.

Legacy s depletion, depreciation, amortization and accretion expense, or DD&A, was $28.4 million and $18.4 million for the years ended December 31, 2007 and 2006, respectively, reflecting primarily (i) $6.3 million of DD&A related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions, (ii) $1.1 million to the Legacy Formation and (iii) $1.6 million related to the South Justis, Farmer Field, and Kinder Morgan Acquisitions.

Impairment expense was $3.2 million and $16.1 million for the years ended December 31, 2007 and 2006, respectively. In 2007 Legacy recognized impairment expense in 43 separate producing fields, due primarily to performance decline in properties within these fields. In 2006 Legacy recognized impairment expense in 41 separate producing fields, due primarily to the decline in oil and natural gas prices from the dates at which the purchase prices for the PITCO acquisition and the Legacy Formation were allocated among the purchased properties. As a point of reference, the NYMEX closing price for oil was $61.05 per Bbl at December 31, 2006, as compared to $66.63 per Bbl on March 31, 2006 at the time of the Legacy Formation and $66.24 per Bbl on September 30, 2005 at the time of the PITCO acquisition. As a point of reference, the NYMEX closing price for natural gas was $6.30 per MMbtu at December 31, 2006, as compared to $7.21 per MMbtu on March 31, 2006 at the time of the Legacy Formation and $13.92 per MMbtu on September 30, 2005 at the time of the PITCO acquisition.

Legacy recorded interest income of $320,968 for the year ended December 31, 2007 and $129,712 for the year ended December 31, 2006. The increase of $191,256 is a result of higher average cash balances during the year ended December 31, 2007.

Interest expense was $7.1 million and $6.6 million for the years ended December 31, 2007 and 2006, respectively, reflecting higher average borrowings during the year ended December 31, 2007 and a mark-to-market adjustment related to interest rate swaps of approximately $1.5 million.

Legacy recorded equity in income of partnership of $77,144 for the year ended December 31, 2007 and a loss of $317,788 for the year ended December 31, 2006. In 2007, Legacy recorded equity in income of partnership related to its non-controlling interest in Binger Operations LP (BOL). This income is primarily derived from BOL s less than 1% interest in the Binger Unit. In 2006, Legacy recorded equity in loss of partnership related to its investment in MBN Management, LLC, which was formed in July, 2005. Legacy did not acquire any interest in MBN Management, LLC as part of the Legacy Formation. Accordingly, such losses will not be incurred in the future.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Legacy s revenues from the sale of oil were $45.4 million and $18.2 million for the years ended December 31, 2006 and 2005, respectively. Legacy s revenues from the sale of natural gas were $14.4 million and $7.3 million for the years ended December 31, 2006 and 2005, respectively. The $27.2 million increase in oil revenues reflects an increase in oil production of 395 MBbls (112%) due primarily to Legacy s purchase of the oil and natural gas properties acquired in the March 15, 2006 formation transactions, or the Legacy Formation, the PITCO acquisition and the South Justis, Farmer Field and Kinder Morgan acquisitions while the realized price excluding the effects of hedging increased $9.07 per Bbl. The $7.1 million increase in natural gas revenues reflects an increase in natural gas production of approximately 1,173 MMcf (114%) due primarily to both the Legacy Formation and the PITCO acquisition while the realized price per Mcf excluding the effects of hedging decreased $0.56 per Mcf. Since the Legacy Formation occurred on March 15, 2006, Legacy s revenues and related volumes for the year ended December 31, 2006 do not reflect the 50 MBbls and 119 MMcf produced by the oil and natural gas properties acquired in that transaction from January 1, 2006 to March 15, 2006. For the year ended December 31, 2006, Legacy recorded $9.3 million of net gains on oil and natural gas swaps comprised of realized losses of $0.3 million from net cash settlements of oil and natural gas swap contracts and net unrealized gains of $9.6 million. Legacy had unrealized net gains from its oil swaps because the fixed price of its oil swap contracts were above the NYMEX index prices at December 31, 2006. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close at December 31, 2006 was $61.05 per Bbl, a price which is less than the average contract prices of Legacy s outstanding oil swap contracts. Legacy had unrealized net gains from its natural gas swaps because the fixed prices of its natural gas swap contracts were above the NYMEX index prices at December 31, 2006. As a point of reference, the NYMEX price for natural gas for the near-month close at December 31, 2006 was $6.30 per MMbtu, a price which is less than the average contract prices of Legacy s outstanding natural gas swap contracts. For the year ended December 31, 2005, Legacy recorded $6.2 million of net losses on oil swaps comprised of a realized loss of $3.5 million from net cash settlements of oil swap contracts and a net unrealized loss of $2.6 million. There were no settlements on natural gas swaps during the year ended December 31, 2005. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods.

Legacy s oil and natural gas production expenses, excluding production and other taxes, increased to $15.9 million ($14.28 per Boe) for the year ended December 31, 2006, from $6.4 ($12.14 per Boe) million for the year ended December 31, 2005. Production expenses increased primarily because of (i) $3.6 million related to the PITCO acquisition, (ii) $3.7 million related to the Legacy Formation, (iii) $2.2 million related to the South Justis, Farmer Field and Kinder Morgan acquisitions and (iv) increased production and increased cost of services and certain operating costs that are directly related to higher commodity prices, particularly the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil.

Legacy s production and other taxes were $3.7 million and $1.6 million for the years ended December 31, 2006 and 2005, respectively. Production and other taxes increased primarily because of (i) approximately $0.8 million of taxes related to the PITCO Acquisition, (ii) $0.9 million of taxes related to the Legacy Formation and (iii) higher commodity prices in the 2006 period.

Legacy s general and administrative expenses were $3.7 million and $1.4 million for the years ended December 31, 2006 and 2005, respectively. General and administrative expenses increased approximately $2.1 million between periods primarily due to increased employee costs related to business expansion and approximately $250,000 of costs incurred in connection with our private equity offering.

Legacy s depletion, depreciation, amortization and accretion expense, or DD&A, was $18.4 million and $2.3 million for the years ended December 31, 2006 and 2005, respectively, reflecting primarily $7.3 million of DD&A related to the PITCO acquisition, $6.8 million to the Legacy Formation and $1.0 million to recent acquisitions.

Impairment expense was $16.1 million for the year ended December 31, 2006 involving 41 separate producing fields, due primarily to the decline in oil and natural gas prices from the dates at which the purchase prices for the PITCO acquisition and the Legacy Formation were allocated among the purchased properties. As a point of reference, the NYMEX closing price for oil was $61.05 per Bbl at December 31, 2006, as compared to $66.63 per Bbl on March 31, 2006 at the time of the Legacy Formation and $66.24 per Bbl on September 30, 2005 at the time of the PITCO acquisition. As a point of reference, the NYMEX closing price for natural gas was $6.30 per MMbtu at December 31, 2006, as compared to $7.21 per MMbtu on March 31, 2006 at the time of the Legacy Formation and $13.92 per MMbtu on September 30, 2005 at the time of the PITCO acquisition.

Legacy recorded interest income of $129,712 for the year ended December 31, 2006 and $185,308 for the years ended December 31, 2005. The decrease of $55,596 is a result of lower average cash balances for the current period.

Interest expense was $6.6 million and $1.6 million for the years ended December 31, 2006 and 2005, respectively, reflecting higher average borrowings and higher average interest rates in the current period. Legacy borrowed $67.5 million to fund the PITCO acquisition and $65.8 million under its new revolving credit facility at the close of the Legacy Formation.

Legacy recorded equity in loss of partnership of $317,788 and $495,295 for the years ended December 31, 2006 and 2005, respectively. In both periods, Legacy recorded equity in loss of partnership related to its investment in MBN Management, LLC, which was formed in July, 2005. Legacy did not acquire any interest in MBN Management, LLC as part of the Legacy Formation. Accordingly, such losses will not be incurred in the future.

Capital Resources and Liquidity

Legacy s primary sources of capital and liquidity have been proceeds from bank borrowings, cash flow from operations, its private offering in March 2006, its initial public offering in January 2007 and its private offering in November 2007. To date, Legacy s primary use of capital has been for the acquisition and development of oil and natural gas properties. During the year ended December 31, 2006, Legacy cancelled (before their original settlement date) a portion of its NYMEX oil swaps covering periods in 2007 and 2008 and realized a loss of $4.0 million. As a result, Legacy s working capital was reduced by $4.0 million. During the year ended December 31, 2005, Legacy cancelled (before their original settlement date) a portion of its NYMEX WTI oil swaps covering periods in 2006 and realized a loss of $2.0 million. Legacy, through its ownership of MBN Properties LP, paid a $0.8 million premium for an option to enter into a $55.00 per Bbl oil swap related to the PITCO acquisition that was not exercised. As a result, Legacy s working capital was reduced by $2.8 million at December 31, 2005.

As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and exploiting additional reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our revolving credit facility, if available, or obtain additional debt or equity financing. Our credit facility imposes certain restrictions on our ability to obtain additional debt financing. Based upon current oil and natural gas price expectations for the year ending December 31, 2008, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our credit facility will provide us sufficient working capital to meet our planned capital expenditures of $18.2 million and planned cash distributions of $53.5 million, which reflects the $13.4 million of distributions paid in the first quarter of 2008 and $13.4 million of planned distributions during each of the second, third and fourth quarters of 2008. Please read Financing Activities Our Revolving Credit Facility.

Cash Flow from Operations

Legacy s net cash provided by operating activities was $57.1 million and $29.6 million for the year ended December 31, 2007 and 2006, respectively, with the 2007 period being favorably impacted by higher sales volumes and realized oil and natural gas prices, partially offset by higher expenses.

Legacy s net cash provided by operating activities was $29.6 million and $14.4 million for the years ended December 31, 2006 and 2005, respectively, with the 2006 period being favorably impacted by higher sales volumes and realized oil and natural gas prices, partially offset by higher expenses.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil and natural gas prices. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through acquisitions and development projects, as well as the prices of oil and natural gas.

We enter into oil, NGL and natural gas derivatives to reduce the impact of oil, NGL and natural gas price volatility on our operations. Currently, we use swaps to offset price volatility on NYMEX oil, NGL and natural gas prices, which do not include the additional net discount that we typically realize in the Permian Basin. At December 31, 2007, we had in place oil, NGL and natural gas swaps covering significant portions of our estimated 2008 through 2012 oil, NGL and natural gas production. As of March 11, 2008 we had derivatives covering approximately 73% of our expected oil, NGL and natural gas production for 2008. As of March 11, 2008 we had also entered into derivative contracts covering approximately 54% of our expected oil, NGL and natural gas production for 2009 through 2012 from existing total proved reserves.

By removing the price volatility on our cash flows from a significant portion of our oil, NGL and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers.

The following tables summarize, for the periods indicated, our oil and natural gas swaps as of March 11, 2008 in place through December 31, 2012. We use swaps as our mechanism for hedging commodity prices whereby we pay the counterparty floating prices and receive fixed prices from the counterparty, which serves to hedge the floating prices we are paid by purchasers of our oil and natural gas. These transactions are settled based upon the NYMEX price of oil at Cushing, Oklahoma, and NYMEX price of natural gas at Henry Hub on the average of the three final trading days of the month and settlement occurs on the fifth day of the production month.

Calendar Year	Annual Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2008	1,135,549	$ 70.39	$ 62.25 - $87.65
2009	1,052,413	$ 68.70	$ 61.05 - $87.65
2010	980,645	$ 67.44	$ 60.15 - $87.65
2011	755,040	$ 72.22	$ 67.33 - $87.65
2012	633,600	$ 72.33	$ 67.72 - $87.65

Calendar Year	Annual Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2008	2,725,170	$ 8.09	$ 6.85 - $10.58
2009	2,524,670	$ 7.96	$ 6.85 - $10.18
2010	2,245,955	$ 7.71	$ 6.85 - $ 9.73
2011	956,824	$ 7.30	$ 6.85 - $ 7.57
2012	651,636	$ 7.25	$ 6.85 - $ 7.57

In July 2006, we entered into basis swaps to receive floating NYMEX prices less a fixed basis differential and pay prices based on the floating Waha index, a natural gas hub in West Texas. The prices that we receive for our natural gas sales follow Waha more closely than NYMEX. The basis swaps thereby provide a better match between our natural gas sales and the settlement payments on our natural gas swaps. The following table summarizes, for the periods indicated, our NYMEX basis swaps as of March 11, 2008 in place through December 31, 2010.

Calendar Year	Annual Volumes (MMBtu)	Basis Range per Mcf	
2008	1,422,000	$	(0.84)
2009	1,320,000	$	(0.68)
2010	1,200,000	$	(0.57)

On March 30, 2007, we entered into natural gas liquids swaps to hedge the impact of volatility in the spot prices of natural gas liquids. On September 7, 2007, we entered into additional natural gas liquids swaps. These swaps hedge the spot prices for ethane, propane, iso-butane, normal butane and natural gasoline tracked on the Mont

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Belvieu, Non-Tet OPIS exchange. The following table summarizes, for the periods indicated, our Mont Belvieu, Non-Tet OPIS natural gas liquids swaps as of March 11, 2008 in place through December 31, 2009.

Calendar Year	Annual Volumes (Gal)	Average Price per Gal	Price Range per Gal
2008	6,458,004	$ 1.27	$ 0.66 - $1.62
2009	2,265,480	$ 1.15	$ 1.15

On March 13, 2008, we entered into additional oil and natural gas swap contracts as described in Note 18 Subsequent Events.

Investing Activities Acquisitions and Capital Expenditures

Legacy s cash capital expenditures were $196.0 million for the year ended December 31, 2007. The total includes $28.5 million, $5.2 million, $14.8 million, $13.5 million, $20.9 million, $62.1 million and $13.5 million for the purchase of producing oil and natural gas properties in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions, respectively. The balance was expended in smaller individual acquisitions and development projects.

Legacy s capital expenditures were $55.9 million and $66.9 million for the years ended December 31, 2006 and 2005, respectively. The total for the year ended December 31, 2006 includes $7.7 million paid to three charitable foundations in the Legacy formation for oil and natural gas properties, $8.9 million, $5.6 million and $17.2 million for the purchase of producing oil and natural gas properties in the South Justis Unit from Henry Holding, LP, the Farmer Field from Larron Oil Corporation and various oil and natural gas properties from Kinder Morgan, respectively, and $7.0 million of capitalized operating rights related to the South Justis Unit. The balance was invested in development projects.

We currently anticipate that our drilling budget, which predominantly consists of drilling, re-completion and re-fracture stimulation projects will be $18.2 million for the year ending December 31, 2008. Our borrowing capacity under our revolving credit facility is $84.4 million as of March 14, 2008. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. If oil and natural gas prices decline below levels we deem acceptable, we may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews. Based upon current oil and natural gas price expectations for the year ending December 31, 2008, we anticipate that we will have sufficient sources of working capital, including our cash flow from operations and available borrowing capacity under our credit facility, to meet our cash obligations including our planned capital expenditures of $18.2 million and planned cash distributions of $53.5 million during the year ending December 31, 2008. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Our Revolving Credit Facility

At the closing of our private equity offering on March 15, 2006, we entered into a four-year, $300 million revolving credit facility with BNP Paribas as administrative agent. Borrowings under the facility are due on March 15, 2010. On October 24, 2007, we entered into the third amendment to the revolving credit facility with BNP Paribas, which increased the maximum credit amount to $500 million from $300 million. Our obligations under the credit facility are secured by mortgages on more than 80% of our oil and gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base, which was initially set at $130 million and increased to $225 million in the third amendment dated October 24, 2007. The borrowing base is subject to semi-annual re-determinations on April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to re-

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determine the borrowing base between scheduled re-determinations. We also have the right, once during each calendar year, to re-determine the borrowing base upon the proposed acquisition of certain oil and gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders and any decrease in the borrowing base must be approved by the lenders holding 662/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 662/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility so long as it does not increase the borrowing base then in effect. Outstanding borrowings in excess of the borrowing base must be prepaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral.

We may elect that borrowings be comprised entirely of alternate base rate (ABR) loans or Eurodollar loans. Interest on the loans is determined as follows:

with respect to ABR loans, the alternate base rate equals the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.25%, or

with respect to any Eurodollar loans, the London inter-bank rate, or LIBOR, plus an applicable margin between 1.00% and 1.75% per annum.

Interest is generally payable quarterly for ABR loans and on the last day of the applicable interest period for any Eurodollar loans.

Our revolving credit facility also contains various covenants that limit our ability to:

incur indebtedness;

enter into certain leases;

grant certain liens;

enter into certain swaps;

make certain loans, acquisitions, capital expenditures and investments;

make distributions other than from available cash;

merge, consolidate or allow any material change in the character of its business; or

engage in certain asset dispositions, including a sale of all or substantially all of our assets.

Our credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization and other similar charges excluding unrealized gains and losses under SFAS No. 133, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures, to interest expense of not less than 2.5 to 1.0; and consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under SFAS No. 133, which includes the current portion of oil, natural gas and interest rate swaps.

If an event of default exists under our revolving credit facility, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Each of the following would be an event of default:

failure to pay any principal when due or any reimbursement amount, interest, fees or other amount within certain grace periods;

a representation or warranty is proven to be incorrect when made;

failure to perform or otherwise comply with the covenants or conditions contained in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;

default by us on the payment of any other indebtedness in excess of $1.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;

bankruptcy or insolvency events involving us or any of our subsidiaries;

the loan documents cease to be in full force and effect our failing to create a valid lien, except in limited circumstances;

a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of March 15, 2006 and persons who are nominated for election or elected to our general partner s board of directors with the approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) Legacy Reserves GP, LLC ceasing to be our sole general partner;

the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and

specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1,000,000 in any year.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2007 is provided in the following table.

	Obligations Due in Period				
Contractual Obligations	**2008**	**2009-2010**	**2011-2012**	**Thereafter**	**Total**
Long-term debt(a)	$	$ 110,000,000	$	$	$ 110,000,000
Interest on long-term debt(b)	7,150,000	8,599,589			15,749,589
Commodity derivatives(c)	26,182,579	38,279,240	17,240,613	569,068	82,271,500
Interest rate derivatives(c)	259,581	1,067,310	168,871		1,495,762
Management Compensation(d)	1,060,000	2,120,000	2,120,000		5,300,000
Office Lease	202,156	416,645	167,237		786,038

Total contractual cash obligations	$ 34,854,316	$ 160,482,784	$ 19,696,721	$ 569,068	$ 215,602,889

(a) Represents amounts outstanding under our revolving credit facility as of December 31, 2007.

(b) Based upon our interest rate of 6.50% under our revolving credit facility as of December 31, 2007.

(c) Derivative obligations represent net liabilities for derivatives that were valued as of December 31, 2007, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read Item 7A. Quantitative and Qualitative Disclosure about Market Risk and Note 9 of Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our derivative obligations.

(d) Does not include any liability associated with management compensation subsequent to the 2011-2012 period as there is no estimated termination date of the employment agreements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Estimates and assumptions are evaluated on a regular basis. Legacy based its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made, and

- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

Please read Note 1 of the Notes to the Consolidated Financial Statements for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

Nature of Critical Estimate Item: Oil and Natural Gas Reserves   Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. LaRoche Petroleum Consultants, Ltd., prepares a reserve and economic evaluation of all our properties in accordance with SEC guidelines on a lease, unit or well-by-well basis, depending on the availability of well-level production data. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the economics of producing the reserves may change and therefore the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion rates are made concurrently with changes to reserve estimates.

Assumptions/Approach Used: Units-of-production method to deplete our oil and natural gas properties   The quantity of reserves could significantly impact our depletion expense. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

Effect if Different Assumptions Used: Units-of-production method to deplete our oil and natural gas properties   A 10% increase or decrease in reserves would have decreased or increased, respectively, our depletion expense for the year ended December 31, 2007 by approximately 10%.

Nature of Critical Estimate Item: Asset Retirement Obligations We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. We adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations effective January 1, 2003. SFAS No. 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets (asset retirement obligations or ARO). Primarily, SFAS No. 143 requires us to estimate asset retirement costs for all of our assets, adjust those costs for inflation to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an ARO liability in that amount with a corresponding addition to our asset value. When new obligations are incurred, i.e. a new well is drilled or acquired, we add a layer to the ARO liability. We then accrete the liability layers quarterly using the applicable period-end effective credit-adjusted-risk-free rates for each layer. Should either the estimated life or the estimated abandonment costs of a property change materially upon our quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. Thus, abandonment costs will almost always approximate the estimate. When well obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from our balance sheet.

Assumptions/Approach Used: Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the estimate of the present value calculation of our AROs are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted-risk-free-rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments.

Effect if Different Assumptions Used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management s judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Unless we expect a well s plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and some significant calculations, could differ from actual results, despite our efforts to make an accurate estimate. We engage independent engineering firms to evaluate our properties annually. We use the remaining estimated useful life from the year-end reserve report by our independent reserve engineers in estimating when abandonment could be expected for each property. On an annual basis we evaluate our latest estimates against actual abandonment costs incurred. For the year ended December 31, 2007, actual abandonment costs materially exceeded our previous estimates. As a result, we revised future estimated costs to reflect these higher actual costs. We expect to see our calculations impacted significantly if interest rates continue to rise, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis.

Nature of Critical Estimate Item: Derivative Instruments and Hedging Activities We periodically use derivative financial instruments to achieve a more predictable cash flow from our oil, NGL and natural gas production and interest expense by reducing our exposure to price fluctuations and interest rate changes. Currently, these transactions are swaps whereby we exchange our floating price for our oil, NGL and natural gas for a fixed price and floating interest rates for fixed rates with qualified and creditworthy counterparties. Our existing oil, NGL, natural gas and interest rate swaps are with members of our lending group which enables us to avoid margin calls for out-of-the money mark-to-market positions.

We do not specifically designate derivative instruments as cash flow hedges, even though they reduce our exposure to changes in oil, NGL and natural gas prices and interest rate changes. Therefore, the mark-to-market of these instruments is recorded in current earnings. While we are not internally preparing an estimate of the current market value of these derivative instruments, we use market value statements from each of our counterparties as the basis for these end-of-period mark-to-market adjustments. When we record a mark-to-market adjustment resulting in a loss in a current period, these unrealized losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future period. As shown in the tables above, we have hedged a significant portion of our future production through 2012. Taking into account the mark-to-market liabilities and assets recorded as of December 31, 2007, the future cash obligations table presented above shows the amounts which we would expect to pay the counterparties over the time periods shown. As oil and gas prices rise and fall, our future cash obligations related to these derivatives will rise and fall.

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Consolidation of Variable Interest Entity

FASB Interpretation (FIN) No. 46 (revised December 2003) Consolidation of Variable Interest Entities, addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and, accordingly, should consolidate the entity. Through March 15, 2006 MBN Properties LP was a variable interest entity since MBN Properties LP required additional subordinated financial support to commence its activities. Legacy consolidated MBN Properties LP as a variable interest entity under FASB FIN 46R because it was the primary beneficiary of MBN Properties LP under the expected losses test of paragraph 14 of FIN 46R. While MBN Management, LLC is a variable interest entity, through March 15, 2006 it was accounted for by Legacy utilizing the equity method since no entity was the primary beneficiary. Legacy s non-controlling income of $538 for the year ended December 31, 2005 represents the loss of MBN Properties LP attributable to the other owners equity interests. As we have acquired all of MBN Properties LP s properties in the formation transactions on March 15, 2006, after that date there are no remaining non-controlling interests related to MBN Properties LP. On April 16, 2007, as a part of the Binger Acquisition, Legacy acquired a 50% non-controlling interest in BOL. While BOL is a variable interest entity, it was accounted for by Legacy utilizing the equity method since no entity was the primary beneficiary.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements.* Statement No. 157 defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in generally accepted account principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for Legacy s financial statements issued in 2008. Although we do not expect any impact to be significant the Statement will affect fair value measurements we make after adoption.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which Legacy elects the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. Legacy does not expect to elect the fair value option for any eligible financial instruments and other items.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, *Amendment of FASB Interpretation No. 39* (FSP FIN 39-1). FSP FIN 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FSP FIN 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Adoption of FSP FIN 39-1 is not expected to have a material impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be Legacy s fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidated Financial Statements an amendments of ARB No. 51 (SFAS 160). SFAS 160 requires that accounting and reporting for minority interests will be re-characterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008, which will be Legacy s fiscal year 2009. Based upon the December 31, 2007 balance sheet, the statement would have no impact.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURE 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 oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably 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 speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the spot market prices applicable to our natural gas production and the prevailing price for crude oil. Pricing for oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, such as the strength of the global economy.

We periodically enter into and anticipate entering into hedging arrangements with respect to a portion of our projected oil and natural gas production through various transactions that hedge the future prices received. These transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into put options, whereby we pay a premium in exchange for the right to receive a fixed price at a future date. At the settlement date we receive the excess, if any, of the fixed floor over the floating rate. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of December 31, 2007, the fair market value of Legacy s derivative positions was a net liability of $83.8 million. As of December 31, 2006, the fair market value of Legacy s derivative positions was a net asset of $3.1 million. The oil, NGL and natural gas swaps for 2008 through December 31, 2012 are tabulated in the table presented above under Cash Flow from Operations.

If oil prices decline by $1.00 per Bbl, then the standardized measure of our combined proved reserves as of December 31, 2007 would decline from $690.5 million to $681.4 million, or 1.3%. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of our combined proved reserves as of December 31, 2007 would decline from $690.5 million to $688.6 million, or 0.3%.

Interest Rate Risks

At December 31, 2007, Legacy had debt outstanding of $110 million, which incurred interest at floating rates in accordance with its revolving credit facility and the subordinated notes payable. The average annual interest rate incurred by Legacy for year ended December 31, 2007 was 7.56%. A 1% increase in LIBOR on Legacy s outstanding debt as of December 31, 2007 would result in an estimated $0.56 million increase in annual interest expense as

Legacy has entered into interest rate swaps to hedge the volatility of interest rates through November of 2011 on $54 million of floating rate debt to a weighted average fixed rate of 4.815%.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Our Consolidated Financial Statements and supplementary financial data are included in this annual report on Form 10-K beginning on page F-1.

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

None.

ITEM 9A(T). *CONTROLS AND PROCEDURES*

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, or the Exchange Act) that are designed to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC 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. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our general partner s Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2007. Based upon that evaluation and subject to the foregoing, our general partner s Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

Our general partner s Chief Executive Officer and Chief Financial Officer do not expect that our disclosure controls or our internal controls will prevent all error and all fraud. The design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be considered relative to their cost. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that we have detected all of our control issues and all instances of fraud, if any. The design of any system of controls also is based partly on certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions.

There have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Annual Report on Internal Control over Financial Reporting

Legacy s management is responsible for establishing and maintaining adequate internal control over financial reporting. Legacy s internal control over financial reporting is a process designed under the supervision of our general partner s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Legacy s financial statements for external purposes in accordance with generally accepted accounting principles. However, Legacy s management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

As of December 31, 2007, management assessed the effectiveness of Legacy s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. This assessment included design effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on that assessment, management determined that Legacy maintained effective internal control over financial reporting as of December 31, 2007, based on those criteria.

This annual report does not include an attestation report of Legacy s registered public accounting firm regarding the internal control over financial reporting. Management s report was not subject to attestation by Legacy s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit Legacy to provide only management s report in this annual report.

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

We intend to include the information required by this Item 10 in Legacy s definitive proxy statement for its 2008 annual meeting of unitholders under the heading Election of Directors, Corporate Governance and Section 16(a) Beneficial Ownership Reporting Compliance, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC no later than 120 days after December 31, 2007.

ITEM 11. *EXECUTIVE COMPENSATION*

We intend to include information with respect to executive compensation in Legacy s definitive proxy statement for its 2008 annual meeting of unitholders under the heading Executive Compensation , which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2007.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS*

We intend to include information regarding Legacy s securities authorized for issuance under equity compensation plans and ownership of Legacy s outstanding securities in Legacy s definitive proxy statement for its 2008 annual meeting of unitholders under the headings Equity Compensation Plan Information and Security Ownership of Certain Beneficial Owners and Management, respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2007.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

We intend to include the information regarding related party transactions in Legacy s definitive proxy statement for its 2008 annual meeting of unitholders under the headings Corporate Governance and Certain Relationships and Related Transactions, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2007.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

We intend to include information regarding principal accountant fees and services in Legacy s definitive proxy statement for its 2008 annual meeting of unitholders under the heading Independent Registered Public Accounting Firm, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2007.

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a)(1) and (2) Financial Statements

The consolidated financial statements of Legacy Reserves LP are listed on the Index to Financial Statements to this annual report on Form 10-K beginning on page F-1.

(a)(3) Exhibits

The following documents are filed as a part of this annual report on Form 10-K or incorporated by reference:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.1)
3.2	Amended and Restated Limited Partnership Agreement of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	Amendment No. 1, dated December 27, 2007, to the Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed January 2, 2008, Exhibit 3.1)
3.4	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.5	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
4.1	Registration Rights Agreement dated as of March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and Friedman, Billings, Ramsey & Co. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 4.1)
4.2	Registration Rights Agreement dated June 29, 2006 between Henry Holdings LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the Henry Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5. 2006, Exhibit 4.2)
4.3	Registration Rights Agreement dated March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties there to (the Founders Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.3)
4.4	Registration Rights Agreement dated April 16, 2007 by and among Nielson & Associates, Inc., Legacy Reserves GP, LLC and Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP s quarterly report on Form 10-Q filed May 14, 2007, Exhibit 4.4)

4.5	Registration Rights Agreement dated as of November 8, 2007 by and among Legacy Reserves LP and the Purchasers named therein (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed November 9, 2007, Exhibit 4.1)
10.1	Credit Agreement dated as of March 15, 2006, among Legacy Reserves LP, the lenders from time to time party thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.1)
10.2	Contribution, Conveyance and Assumption Agreement dated as of March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.2)

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Exhibit Number	Description
10.3	Omnibus Agreement dated as of March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.3)
10.4	Purchase/Placement Agreement dated as of March 6, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties there to (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.4)
10.5	Legacy Reserves, LP Long-Term Incentive Plan (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.5)
10.6	First Amendment of Legacy Reserves LP to Long Term Incentive Plan dated June 16, 2006 (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed October 5, 2006, Exhibit 10.17)
10.7	Amended and Restated Legacy Reserves LP Long-Term Incentive Plan effective as of August 17, 2007 (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed August 23, 2007, Exhibit 10.1)
10.8	Form of Legacy Reserves LP Long-Term Incentive Plan Restricted Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.6)
10.9	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Option Grant Agreement (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.7)
10.10	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.8)
10.11	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed February 4, 2008, Exhibit 10.1)
10.12	Employment Agreement dated as of March 15, 2006 between Cary D. Brown and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333- 134056) filed May 12, 2006, Exhibit 10.9)
10.13	Employment Agreement dated as of March 15, 2006 between Steven H. Pruett and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.10)
10.14	Employment Agreement dated as of March 15, 2006 between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.11)
10.15	Employment Agreement dated as of March 15, 2006 between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333- 134056) filed May 12, 2006, Exhibit 10.12)
10.16	Employment Agreement dated as of March 15, 2006 between William M. Morris and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.13)
10.17	First Amendment to Credit Agreement effective as of July 7, 2006 among Legacy Reserves LP, the lenders from time to time party thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.14)

10.18	Second Amendment to Credit Agreement dated May 3, 2007 among Legacy Reserves LP, the lenders from time to time party thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed May 8, 2007, Exhibit 10.1)
10.19	Third Amendment to Credit Agreement dated October 24, 2007 among Legacy Reserves LP, the lenders from time to time party thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed October 29, 2007, Exhibit 10.1)

Exhibit Number	Description
10.20	Purchase and Sale Agreement dated June 29, 2006 between Kinder Morgan Production Company LP and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed October 5, 2006, Exhibit 10.15)
10.21	Purchase and Sale Agreement dated June 13, 2006 between Henry Holding LP and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.16)
10.22	Purchase and Sale Agreement dated March 29, 2007, by and among Ameristate Exploration, LLC and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed May 4, 2007, Exhibit 10.1)
10.23	Purchase, Sale and Contribution Agreement dated March 20, 2007, by and among Nielson & Associates, Inc. and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s quarterly report on Form 10-Q filed May 14, 2007, Exhibit 10.1)
10.24	Purchase, Sale and Contribution Agreement dated March 20, 2007, by and among Terry S. Fields and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s quarterly report on Form 10-Q filed August 13, 2007, Exhibit 10.1)
10.25	Purchase, Sale and Contribution Agreement dated May 3, 2007, by and among Raven Resources, LLC and Shenandoah Petroleum Corporation and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s quarterly report on Form 10-Q filed August 13, 2007, Exhibit 10.2)
10.26	Purchase, Sale and Contribution Agreement dated July 11, 2007, by and among Raven Resources, LLC and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s quarterly report on Form 10-Q filed November 9, 2007, Exhibit 10.1)
10.27	Purchase, Sale and Contribution Agreement dated August 28, 2007, by and among Summit Petroleum Management Corporation and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s quarterly report on Form 10-Q filed November 9, 2007, Exhibit 10.3)
10.28	Purchase, Sale and Contribution Agreement dated August 30, 2007, by and among The Operating Company and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s quarterly report on Form 10-Q filed November 9, 2007, Exhibit 10.4)
10.29	Unit Purchase Agreement dated as of November 7, 2007 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the Purchasers named therein (Incorporated by reference to Legacy Reserves LP s current report on Form 8-K filed November 9, 2007, Exhibit 10.1)
21.1	List of subsidiaries of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 21.1)
23.1*	Consent of BDO Seidman LLP
23.2*	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	Rule 13a-14(a) Certification of CEO (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	Rule 13a-14(a) Certification of CFO (under Section 302 of the Sarbanes-Oxley Act of 2002)
32.1*	Section 1350 Certifications (under Section 906 of the Sarbanes-Oxley Act of 2002)

* Filed herewith

Management contract or compensatory plan or arrangement

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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 annual report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Midland, State of Texas, on the 11th day of December, 2008.

LEGACY RESERVES LP

By: LEGACY RESERVES GP, LLC,

its general partner

By: /s/ Steven H. Pruett

Name: Steven H. Pruett

Title: President, Chief Financial Officer and Secretary (Principal Financial Officer)

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Legacy Reserves LP
Midland, Texas

We have audited the accompanying consolidated balance sheets of Legacy Reserves LP (formerly the Moriah Group, as defined in Note 1 (a)), as of December 31, 2006 and 2007 and the related consolidated statements of operations, unitholders equity, and cash flows for each of the years in the three year period ended December 31, 2007. 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. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our 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 Legacy Reserves LP at December 31, 2006 and 2007 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO SEIDMAN, LLP

Houston, Texas
March 13, 2008

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LEGACY RESERVES LP

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2006 AND 2007

	2006	2007
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,062	$ 9,604
Accounts receivable, net:		
Oil and natural gas	7,600	19,025
Joint interest owners	4,345	4,253
Affiliated entities and other (Notes 3 and 6)	21	26
Fair value of derivatives (Note 9)	5,102	310
Prepaid expenses and other current assets	91	340
Total current assets	18,221	33,558
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, at cost, using the successful efforts method of accounting (Note 14):	289,519	512,396
Unproved properties	68	78
Accumulated depletion, depreciation and amortization	(42,007)	(72,294)
	247,580	440,180
Other property and equipment, net of accumulated depreciation and amortization of $51 and $251, respectively	304	775
Operating rights, net of amortization of $295 and $865, respectively (Note 1(k))	6,721	6,151
Other assets, net of amortization of $167 and $391, respectively	542	822
Investment in equity method investee (Note 5)		92
	$ 273,368	$ 481,578
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 2,932	$ 2,320
Accrued oil and natural gas liabilities	5,882	10,102
Fair value of derivatives (Note 9)		26,761
Asset retirement obligation (Note 11)	553	845
Other (Note 13)	1,467	3,429
Total current liabilities	10,834	43,457

Long-term debt (Note 3)	115,800	110,000
Asset retirement obligation (Note 11)	5,939	15,075
Fair value of derivatives (Note 9)	2,006	57,316
Total liabilities	134,579	225,848
Commitments and contingencies (Note 7)		
Unitholders equity:		
Limited partners equity 18,395,233 and 29,670,887 units issued and outstanding at December 31, 2006 and 2007, respectively	138,653	255,663
General partner s equity (approximately 0.1)%	136	67
Total unitholders equity	138,789	255,730
Total liabilities and unitholders equity	$ 273,368	$ 481,578

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2005, 2006 AND 2007

	2005	2006	2007
	(Dollars in thousands, except per unit data)		
Revenues:			
Oil sales	$ 18,225	$ 45,351	$ 83,301
Natural gas liquid sales			7,502
Natural gas sales	7,318	14,446	21,433
Total revenues	25,543	59,797	112,236
Expenses:			
Oil and natural gas production	6,376	15,938	27,129
Production and other taxes	1,636	3,746	7,889
General and administrative	1,354	3,691	8,392
Depletion, depreciation, amortization and accretion	2,291	18,395	28,415
Impairment of long-lived assets		16,113	3,204
Loss on disposal of assets	20	42	527
Total expenses	11,677	57,925	75,556
Operating income	13,866	1,872	36,680
Other income (expense):			
Interest income	185	130	321
Interest expense (Notes 3 and 9)	(1,584)	(6,645)	(7,118)
Equity in income (loss) of partnerships (Note 5)	(495)	(318)	77
Realized gain (loss) on oil, NGL and natural gas swaps (Note 9)	(3,531)	(262)	211
Unrealized gain (loss) on oil, NGL and natural gas swaps (Note 9)	(2,628)	9,551	(85,367)
Other	45	29	(129)
Income (loss) before non-controlling interest and income taxes	5,858	4,357	(55,325)
Non-controlling interest	1		
Income (loss) before income taxes	5,859	4,357	(55,325)
Income taxes			(337)
Net income (loss)	$ 5,859	$ 4,357	$ (55,662)
Net income (loss) per unit basic and diluted (Note 12)	$ 0.62	$ 0.26	$ (2.13)

Weighted average number of units used in computing net income (loss) per unit basic	9,488,921	16,567,287	26,155,439
diluted	9,488,921	16,568,879	26,155,439

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENT OF UNITHOLDERS EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2005, 2006 AND 2007

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders Equity
		(Dollars in thousands)		
Balance December 31, 2004	9,488,921	$ 12,010	$ 12	$ 12,022
Capital contributions		144		144
Deemed capital distribution		155		155
Distributions to partners		(8,263)	(8)	(8,271)
Net income		5,853	6	5,859
Balance December 31, 2005	9,488,921	9,899	10	9,909
Capital contributions		19		19
Net distributions to owners		(2,295)	(2)	(2,297)
Deemed dividend to Moriah Group owners		(3,874)	(4)	(3,878)
Net proceeds from private equity offering	5,000,000	76,707	77	76,784
Redemption of Founding Investors units	(4,400,000)	(69,868)	(70)	(69,938)
Units issued to MBN Properties LP in exchange for the non-controlling interests share of oil and natural gas properties	1,867,290	31,712	32	31,744
Units issued to the Brothers Group in exchange for oil and natural gas properties and other assets	6,200,358	105,301	105	105,406
Units issued to H2K Holdings Ltd in exchange for oil and natural gas properties	83,499	1,418	1	1,419
Dividend reimbursement of offering costs paid by MBN Management LLC		(1,199)	(1)	(1,200)
Units issued to Henry Holding LP in exchange for oil and natural gas properties	146,415	2,489		2,489
Units issued to Legacy Board of Directors for services	8,750	149		149
Compensation expense on unit options granted to employees		115		115
Compensation expense on restricted unit awards issued to employees		270		270
Distributions to unitholders, $0.8974 per unit		(16,542)	(16)	(16,558)
Net income		4,352	4	4,356
Balance, December 31, 2006	18,395,233	138,653	136	138,789
Net proceeds from initial public equity offering	6,900,000	121,554		121,554
	3,642,369	73,073		73,073

Net proceeds from private placement equity offering				
Units issued to Legacy Board of Directors for services	7,000	149		149
Compensation expense on restricted unit awards issued to employees		341		341
Vesting of Restricted Units	20,038			
Units issued to Greg McCabe in exchange for oil and natural gas properties	95,000	2,271		2,271
Units issued to Nielson & Associates, Inc. in exchange for oil and natural gas properties	611,247	15,752		15,752
Reclass prior period compensation cost on unit options granted to employees to adjust for conversion to liability method as described in FAS 123-R		(115)		(115)
Distributions to unitholders, $1.67 per unit		(40,388)	(34)	(40,422)
Net loss		(55,627)	(35)	(55,662)
Balance, December 31, 2007	29,670,887	$ 255,663	$ 67	$ 255,730

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2005, 2006 AND 2007

	2005	2006	2007
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 5,859	$ 4,357	$ (55,662)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	2,291	18,395	28,415
Amortization of debt issuance costs	94	361	224
Impairment of long-lived assets		16,113	3,204
(Gain) loss on derivatives	6,159	(9,289)	86,652
Equity in (income) loss of partnership	495	318	(77)
Accrued interest on subordinated notes payable partners	818		
Accrued interest on subordinated notes receivable partners	(25)		
Amortization of unit-based compensation		534	166
Non-controlling interest	(1)		
Loss on disposal of assets	21	42	527
Changes in assets and liabilities:			
Increase in accounts receivable, oil and natural gas	(3,412)	(5,796)	(11,425)
(Increase) decrease in accounts receivable, joint interest owners	605	(4,481)	92
Increase in accounts receivable, other	(91)	(458)	(5)
Increase in prepaid expenses and other current assets	(88)	(565)	(250)
Increase (decrease) in accounts payable	395	2,694	(611)
Increase in accrued oil and natural gas liabilities	1,107	4,227	4,221
Increase in due to affiliates	195	1,059	
Increase (decrease) in other current liabilities	(13)	2,079	1,676
Total adjustments	8,550	25,233	112,809
Net cash provided by operating activities	14,409	29,590	57,147
Cash flows from investing activities:			
Investment in oil and natural gas properties	(66,910)	(55,907)	(196,031)
Investment in other equipment	(4)	(243)	(671)
Investment in operating rights		(7,017)	
Investment in notes receivable	(900)		
Collection of notes receivable	2,380	924	
Net cash settlements on oil and natural gas swaps	(3,531)	(262)	211
Investment in equity method investee			(14)
Net cash used in investing activities	(68,965)	(62,505)	(196,505)

Cash flows from financing activities:			
Proceeds from long-term debt	56,573	121,800	183,000
Payments of long-term debt	(6,100)	(73,190)	(188,800)
Payments of debt issuance costs	(868)	(293)	(505)
Proceeds from subordinated notes payable partners	14,264		
Proceeds from issuance of units, net		76,784	194,627
Redemption of Founding Investors units		(69,938)	
Dividend reimbursement of offering costs paid by MBN Management LLC		(1,200)	
Capital contributed by owner	144	19	
Cash not acquired in Legacy formation transactions		(3,104)	
Distributions to unitholders	(8,271)	(18,856)	(40,422)
Net cash provided by financing activities	55,742	32,022	147,900
Net increase(decrease)in cash and cash equivalents	1,186	(893)	8,542
Cash and cash equivalents, beginning of period	769	1,955	1,062
Cash and cash equivalents, end of period	$ 1,955	$ 1,062	$ 9,604

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	2005	2006	2007
	(Dollars in thousands)		
Non Cash Investing and Financing Activities:			
Asset retirement obligation costs and liabilities	$ 12	$ 2,273	$ 6,296
Asset retirement obligations associated with property acquisitions	$ 445	$ 1,889	$ 3,034
Contributed offering costs	$ 155	$	$
Non-controlling interests share of net financing costs of MBN Properties LP capitalized to oil and natural gas properties	$	$ 164	$
Units issued to MBN Properties LP in exchange for the non-controlling interests share of oil and natural gas properties	$	$ 31,744	$
Units issued to Brothers Group in exchange for:			
Oil and natural gas properties	$	$ 105,299	$
Other property and equipment	$	$ 107	$
Units issued to H2K Holdings Ltd. in exchange for oil and natural gas properties	$	$ 1,419	$
Oil and natural gas hedge liabilities assumed from the Brothers Group and H2K Holdings Ltd.	$	$ 3,147	$
Units issued in exchange for oil and natural gas properties	$	$ 2,489	$ 18,023
Deemed dividend to Moriah Group owners for accounts not acquired in Legacy formation transaction:			
Accounts receivable, oil and natural gas	$	$ 4,248	$
Accounts receivable, joint interest owners	$	$ 250	$
Accounts receivable, other	$	$ 540	$
Other assets	$	$ 891	$
Accounts payable	$	$ (214)	$
Accrued oil and natural gas liabilities	$	$ (1,521)	$

Due to affiliates	$	$	(1,254)	$
Other liabilities	$	$	(2,166)	$

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) Organization, Basis of Presentation and Description of Business

On March 15, 2006, Legacy Reserves LP (LRLP, Legacy or the Partnership), as the successor entity to the Moriah Group (defined below), completed a private equity offering in which it (1) issued 5,000,000 limited partnership units at a gross price of $17.00 per unit, netting $76.8 million after initial purchaser s discount, placement agent s fee and expenses, (2) acquired certain oil and natural gas properties (Note 4) and (3) redeemed 4.4 million units for $69.9 million from certain of its Founding Investors. The Moriah Group has been treated as the acquiring entity in this transaction, hereinafter referred to as the Legacy Formation. Because the combination of the businesses that comprised the Moriah Group was a reorganization of entities under common control, the combination of these businesses has been reflected retroactively at carryover basis in these consolidated financial statements. The accounts presented for periods prior to the Legacy Formation transaction are those of the Moriah Group.

LRLP and its affiliated entities are referred to as Legacy in these financial statements.

LRLP, a Delaware limited partnership, was formed by its general partner, Legacy Reserves GP, LLC (LRGPLLC), on October 26, 2005 to own and operate oil and natural gas properties. LRGPLLC is a Delaware limited liability company formed on October 26, 2005, and it owns an approximately 0.1% general partner interest in LRLP.

Significant information regarding rights of the limited partners includes the following:

- Right to receive distributions of available cash within 45 days after the end of each quarter.
- No limited partner shall have any management power over our business and affairs; the general partner shall conduct, direct and manage LRLP s activities.
- The general partner may be removed if such removal is approved by the unitholders holding at least 662/3 percent of the outstanding units, including units held by LRLP s general partner and its affiliates.
- Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year

In the event of a liquidation, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and LRLP s general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of Legacy s assets in liquidation.

As used herein, the term Moriah Group refers to Moriah Resources, Inc. (MRI), Moriah Properties, Ltd. (MPL), the oil and natural gas interests individually owned by Dale A. and Rita Brown and the accounts of MBN Properties LP on a consolidated basis unless the context specifies otherwise. Prior to March 15, 2006, the accompanying financial statements include the accounts of the Moriah Group. From March 15, 2006, the accompanying financial statements also include the results of operations of the oil and natural gas properties acquired in the Legacy Formation transaction. All significant intercompany accounts and transactions have been eliminated. The Moriah Group consolidated MBN Properties LP as a variable interest entity under FASB FIN 46R since the Moriah Group was the primary beneficiary of MBN Properties LP. The partners, shareholders and owners of these entities have other investments, such as real estate, that are held either individually or through other legal entities that are not presented as part of these financial statements. The accompanying financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred.

MRI was organized as a sub-chapter S corporation on September 28, 1992 under the laws of the State of Texas, and serves as the 1% general partner to MPL. MPL was organized as a limited partnership on July 1, 1999 under the laws of the State of Texas. Dale A. Brown, an individual, has owned oil and natural gas working interests since 1981.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Dale A. Brown, who along with his son, Cary D. Brown, are the sole owners of MRI and MPL. The assets of Moriah Properties New Mexico, Ltd. (MNM), a limited partnership organized under the laws of the State of Texas on October 17, 2003, were assigned into MPL effective September 1, 2005, in order to streamline the business of the limited partnerships with identical ownership and a shared general partner, MRI, and the accounts of MNM have been reflected retroactively in the financial statements of MPL. Effective October 1, 2005, Dale and Rita Brown assigned the selected oil and natural gas properties included in these consolidated financial statements to DAB Resources, Ltd., a Texas limited partnership they own.

On July 22, 2005, MPL advanced $1,649,132 which was recorded as paid in capital and subordinated notes receivable to MBN Properties LP which utilized the capital to fund a deposit with The Prospective Investment and Trading Company, Ltd. (PITCO) and its affiliates for the purchase of oil and natural gas properties described below. MPL also advanced $654,099 to fund the expenses of MBN Management LLC, the general partner of MBN Properties LP. Of this amount, $467 was for paid in capital and the balance of $653,632 was in a note receivable from MBN Management LLC. MBN Properties LP, a Delaware limited partnership, and MBN Management LLC, a Delaware limited liability company, (collectively the MBN Group) were formed to acquire and operate oil and natural gas producing properties in partnership with Brothers Production Properties, Ltd., and certain third party investors. Cary D. Brown, the Executive Vice President of MRI and its 50% owner, is the Chief Executive Officer and a Director of MBN Management LLC. On September 14, 2005, MBN Properties LP purchased oil and natural gas producing properties located in the Permian Basin from PITCO and its affiliates for $66,151,723 (the PITCO Acquisition), subject to post-closing adjustments. While MBN Management LLC is a variable interest entity, the Moriah Group accounted for its interest in that entity using the equity method since it is not the primary beneficiary of MBN Management LLC under the expected losses test of paragraph 14 of FAS FIN 46R.

Legacy owns and operates oil and natural gas producing properties located primarily in the Permian Basin of West Texas and southeast New Mexico. Legacy has acquired oil and natural gas producing properties and drilled leasehold.

(b) Cash Equivalents

For purposes of the consolidated statement of cash flows, Legacy considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

(c) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. Legacy routinely assesses the financial strength of its customers. Bad debts are recorded based on an account-by-account review after all means of collection have been exhausted and potential recovery is considered remote. Legacy does not have any off-balance-sheet credit exposure related to its customers (see Note 10).

(d) Oil and Natural Gas Properties

Legacy accounts for oil and natural gas properties by the successful efforts method. Under this method of accounting, costs relating to the acquisition of and development of proved areas are capitalized when incurred. The costs of development wells are capitalized whether productive or non-productive. Leasehold acquisition costs are capitalized when incurred. If proved reserves are found on an unproved property, leasehold cost is transferred to proved properties. Exploration dry holes are charged to expense when it is determined that no commercial reserves exist. Other exploration costs, including personnel costs, geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense when incurred. The costs of acquiring or constructing support equipment and facilities used in oil and gas producing activities are capitalized. Production costs are charged to expense as incurred and are those costs incurred to operate and maintain our wells and related equipment and facilities.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Depreciation and depletion of producing oil and natural gas properties is recorded based on units of production. FAS No. 19 requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (wells and related equipment and facilities) be amortized on the basis of proved developed reserves. As more fully described below, proved reserves are estimated annually by the Legacy s independent petroleum engineer, LaRoche Petroleum Consultants, Ltd., and are subject to future revisions based on availability of additional information. Legacy s in-house reservoir engineers prepare an updated estimate of reserves each quarter. Depletion is calculated each quarter based upon the latest estimated reserves data available. As discussed in Note 11, Legacy follows FAS No. 143. Under FAS No. 143, asset retirement costs are recognized when the asset is placed in service, and are amortized over proved reserves using the units of production method. Asset retirement costs are estimated by Legacy s engineers using existing regulatory requirements and anticipated future inflation rates.

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds from sale or salvage value, is charged to income. On sale or retirement of an individual well the proceeds are credited to accumulated depletion and depreciation.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy assesses impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using oil and natural gas prices as of the last day of the statement period held constant. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. As of December 31, 2005, the estimated undiscounted future cash flows for Legacy s proved oil and natural gas properties exceeded the net capitalized costs, and no impairment was required to be recognized. For the year ended December 31, 2006, Legacy recognized $16.1 million of impairment expense on 41 separate producing fields related primarily to the decline in natural gas and oil prices from the dates at which the purchase prices for the PITCO acquisition and the formation transaction were allocated among the purchased properties. As of December 31, 2007, Legacy recognized $3.2 million of impairment expense on 43 separate producing fields related primarily to the decline in performance on individual properties.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Costs related to unproved mineral interests that are individually insignificant are amortized over the shorter of the exploratory period or the lease/concession holding period which is typically three years in the Permian Basin.

(e) Oil and Natural Gas Reserve Quantities

Legacy s estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. LaRoche Petroleum Consultants, Ltd. prepares a reserve and economic evaluation of all Legacy s properties on a well-by-well basis utilizing information provided to it by Legacy and information available from state agencies that collect information reported to it by the operators of Legacy s properties.

Reserves and their relation to estimated future net cash flows impact Legacy s depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Legacy prepares its reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing their reserve report. The accuracy of Legacy s reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Legacy s proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas, and natural gas liquids eventually recovered.

(f) Income Taxes

Legacy is structured as a limited partnership, which is a pass-through entity for United States income tax purposes.

In May 2006, the State of Texas enacted a new margin-based franchise tax law that replaced the existing franchise tax. This new tax is commonly referred to as the Texas margin tax and is assessed at a 1% rate. Corporations, limited partnerships, limited liability companies, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the new tax. The tax is considered an income tax and is determined by applying a tax rate to a base that considers both revenues and expenses. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. This franchise tax report covers our taxable activities for the year ended December 31, 2007.

Legacy recorded income tax expense of $337,000 for the year ended December 31, 2007 which consists primarily of the Texas margin tax and federal income tax on a corporate subsidiary which employs full and part-time personnel providing services to the Partnership. The Partnership s total effective tax rate differs from statutory rates for federal and state purposes primarily due to being structured as a limited partnership, which is a pass-through entity for federal income tax purposes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. In addition, individual unitholders have different investment bases depending upon the timing and price of acquisition of their common units, and each unitholder s tax accounting, which is partially dependent upon the unitholder s tax position, differs from the accounting followed in the consolidated financial statements. As a result, the aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Partnership does not have access to information about each unitholder s tax attributes in the Partnership. However, with respect to the Partnership, the difference between the Partnership s net book basis and the Partnership s net tax basis is $189.2 million.

(g) Derivative Instruments and Hedging Activities

Legacy periodically uses derivative financial instruments to achieve a more predictable cash flow from its oil and natural gas production by reducing its exposure to price fluctuations and interest rate changes. Legacy accounts for these activities pursuant to FAS No. 133 *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair market value and included in the balance sheet as assets or liabilities.

Legacy does not specifically designate derivative instruments as cash flow hedges, even though they reduce its exposure to changes in oil and natural gas prices and interest rate changes. Therefore, the cash settlements and mark-to-market of oil, NGL and natural gas derivatives are recorded in current earnings. Interest rate derivative effects are recorded in interest expense (see Note 9).

(h) Use of Estimates

Management of Legacy has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ materially from those estimates. Estimates which are particularly significant to the

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

consolidated financial statements include estimates of oil and natural gas reserves, valuation of derivatives, future cash flows from oil and natural gas properties, depreciation, depletion and amortization and asset retirement obligations.

(i) Revenue Recognition

Sales of crude oil, natural gas liquids and natural gas are recognized when the delivery to the purchaser has occurred and title has been transferred. This occurs when oil or natural gas has been delivered to a pipeline or a tank lifting has occurred. Crude oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. Virtually all of Legacy s natural gas contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. These market indices are determined on a monthly basis. As a result, Legacy s revenues from the sale of oil and natural gas will suffer if market prices decline and benefit if they increase. Legacy believes that the pricing provisions of its oil and natural gas contracts are customary in the industry.

Legacy currently uses the net-back method of accounting for transportation arrangements of its natural gas sales. Legacy sells natural gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by its purchasers and reflected in the wellhead price. Legacy s contracts with respect to the sale of its natural gas produced, with one immaterial exception, provide Legacy with a net price payment. That is, Legacy is paid for its natural gas by its purchasers, Legacy receives a price which is net of any costs incurred for treating, transportation, compression, etc. In accordance with the terms of Legacy s contracts, the payment statements Legacy receives from its purchasers show a single net price without any detail as to treating, transportation, compression, etc. Thus, Legacy s revenues are recorded at this single net price.

Natural gas imbalances occur when Legacy sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of its share is treated as a liability. If Legacy receives less than its entitled share the underproduction is recorded as a receivable. Legacy did not have any significant natural gas imbalance positions as of December 31, 2005, 2006 or 2007.

Legacy is paid a monthly operating fee for each well it operates for outside owners. The fee covers monthly general and administrative costs. As the operating fee is a reimbursement of costs incurred on behalf of third parties, the fee has been netted against general and administrative expense.

(j) Investments

Undivided interests in oil and natural gas properties owned through joint ventures are consolidated on a proportionate basis. Investments in entities where Legacy exercises significant influence, but not a controlling interest are accounted for by the equity method. Under the equity method, Legacy s investments are stated at cost plus the equity in undistributed earnings and losses after acquisition.

(k) Intangible assets

Legacy has capitalized certain operating rights acquired in the acquisition of oil and gas properties (Note 4). The operating rights, which have no residual value, are amortized over their estimated economic life of approximately 15 years beginning July 1, 2006. Amortization expense is included as an element of depletion, depreciation, amortization and accretion expense. Impairment will be assessed on a quarterly basis or when there is a material change in the remaining useful life. The expected amortization expense for 2008, 2009, 2010, 2011 and 2012 is $547,000, $537,000, $522,000, $510,000 and $502,000, respectively.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(l) Environmental

Legacy is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require Legacy to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation are probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments are fixed and readily determinable.

(m) Earnings (Loss) Per Unit

Legacy computes its earnings (loss) per unit in accordance with SFAS No. 128, *Earnings per Share*, which requires the presentation of basic and diluted earnings per unit on the face of the income statement. Basic earnings per unit amounts are calculated using the weighted average number of units outstanding during each period. Diluted earnings per unit also gives effect to dilutive unvested restricted units and unit options (calculated based upon the treasury stock method).

Basic and diluted earnings per unit for the year ended December 31, 2005 were computed based on the 9,488,921 units issued to the Moriah Group on March 15, 2006 in exchange for oil and natural gas properties contributed by it (including its indirect interest in oil and natural gas properties contributed by MBN Properties, LP) in conjunction with the closing of the Legacy Formation on the same date.

(n) Redemption of Units

Units redeemed are recorded at cost.

(o) Segment Reporting

Legacy s management treats each new acquisition of oil and natural gas properties as a separate operating segment. Legacy aggregates these operating segments into a single segment for reporting purposes.

(p) Unit-Based Compensation

Concurrent with the Formation Transaction on March 15, 2006, a Long-Term Incentive Plan (LTIP) for Legacy was created and Legacy adopted SFAS No. 123(R), Share-Based Payment. Due to Legacy s history of cash settlements for option exercises, Legacy accounts for unit options under the liability method of SFAS No. 123(R). This method requires the Partnership to recognize the fair value of each unit option at the end of each period. Expense is recognized as a change in the liability from period to period. Pursuant to the provisions of SFAS 123(R), Legacy s issued units, as reflected in the accompanying consolidated balance sheet at December 31, 2007 does not include 45,078 units related to unvested restricted unit awards.

(q) Recently Issued Accounting pronouncements

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements.* Statement No. 157 defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in generally accepted account principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for Legacy s financial statements issued in 2008. Although we do not expect any impact to be significant the Statement will affect fair value measurements we make after adoption.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which Legacy elects the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. Legacy does not expect to elect the fair value option for any eligible financial instruments and other items.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, Amendment of FASB Interpretation No. 39 (FSP FIN 39-1). FSP FIN 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FSP FIN 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Adoption of FSP FIN 39-1 is not expected to have a material impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be the Partnership s fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidated Financial Statements an amendments of ARB No. 51 (SFAS 160). SFAS 160 requires that accounting and reporting for minority interests will be re-characterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008, which will be the Partnership s fiscal year 2009. Based upon the December 31, 2007 balance sheet, the statement would have no impact.

(r) Prior Year Financial Statement Presentation

Certain prior year balances have been reclassified to conform to the current year presentation of balances as stated in this annual report on Form 10-K.

(2) Fair Values of Financial Instruments

The estimated fair values of Legacy s financial instruments closely approximate the carrying amounts as discussed below:

Cash and cash equivalents, accounts receivable, other current assets, accounts payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Notes receivable. The carrying amounts approximate fair value due to the comparability of the interest rate to market interest rates for instruments of similar terms and credit quality.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt. The carrying amount of the revolving long-term debt approximates fair value because Legacy s current borrowing rate does not materially differ from market rates for similar bank borrowings.

Commodity price derivatives. The fair market values of commodity derivative instruments are estimated based upon the current market price of the respective commodities at the date of valuation. It represents the amount which Legacy would be required to pay or able to receive, based upon the differential between a fixed and a variable commodity price as specified in the hedge contracts.

Interest rate derivatives. The fair market values of interest rate derivative instruments are estimated based upon the current market LIBOR rates for the respective notional amount at the date of valuation. It represents the difference between the fixed rate as specified in the hedge contracts and the floating rate applicable to the notional amounts.

(3) Credit Facility

On September 13, 2005, the Moriah Group replaced its Credit Agreement with a new Senior Credit Facility (the New Facility) with a new lending group that permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $75 million. The borrowing base under the New Facility, initially set at $40 million, was subject to re-determination every six months and was subject to adjustment based upon changes in the fair market value of the Moriah Group s oil and natural gas assets. Interest on the New Facility was payable monthly and was charged in accordance with the Moriah Group s selection of a LIBOR rate plus 1.5% to 2.0%, or prime rate up to prime rate plus 0.5%, dependent on the percentage of the borrowing base which was drawn. Borrowings under this New Facility were due in September 2009. The New Facility contained certain loan covenants requiring minimum financial ratio coverages, involving the current ratio and EBITDA to interest expense. On September 13, 2005, the Moriah Group borrowed $22,123,000 from the new lending group to provide for general corporate purposes, to fund a $4.2 million distribution to Cary Brown and Dale Brown and to advance additional subordinated notes receivable in the amount of $17,598,000 to MBN Properties LP, which purchased oil and natural gas producing properties from PITCO. The Moriah Group s interest rate at December 31, 2005 was 6.0%. The Moriah Group paid interest expense on this debt of $220,638 for the year ended December 31, 2005 and $264,062 for the period from January 1, 2006 through March 15, 2006. At December 31, 2005, the Moriah Group was in compliance with all aspects of the Agreement. All amounts outstanding under this agreement at March 15, 2006 were repaid in full on that date as part of the formation transactions.

On September 13, 2005, MBN Properties LP entered into a Credit Agreement with a new Senior Credit Facility (the MBN Facility) with a lending group that permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $75 million. The borrowing base under the MBN Facility, initially set at $35 million, was subject to re-determination every six months and was subject to adjustment based upon changes in the fair market value of the MBN Properties LP s oil and natural gas assets. Interest on the MBN Facility was payable monthly and was charged in accordance with MBN Properties LP s selection of a LIBOR rate plus 1.5% to 2.0%, or prime rate up to prime rate plus 0.50%, dependent on the percentage of the borrowing base which was drawn. Borrowings under this MBN Facility were due in September 2007. The MBN Facility contained certain loan covenants requiring minimum financial ratio coverages, involving the current ratio and EBITDA to interest expense. On September 13, 2005, MBN Properties LP borrowed $33,750,000 from the new lending group to purchase oil and natural gas producing properties from PITCO. The MBN Properties LP s interest rate at December 31, 2005 was 6.33%. MBN Properties LP paid interest expense of $431,085 on this debt for the period from inception to December 31, 2005 and $1,300,727 for the period from January 1, 2006 through March 15, 2006. At December 31, 2005, MBN Properties LP was in compliance with all aspects of the Agreement. All amounts outstanding under this agreement at March 15, 2006 were repaid in full on that date as part of the formation transactions.

As an integral part of the Legacy Formation, Legacy entered into a new credit agreement with a new senior credit facility (the Legacy Facility) with the same lending group that participated in the New Facility of the Moriah Group. Legacy s oil and natural gas properties are pledged as collateral for any borrowings under the

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Legacy Facility. Borrowings under the Legacy Facility are due on March 15, 2010. The terms of the Legacy Facility permits borrowings in the lesser amount of (i) the borrowing base, or (ii) $500 million. The borrowing base under the Legacy Facility, which was initially set at $130 million, is re-determined every six months and will be adjusted based upon changes in the fair market value of the Partnership s oil and natural gas assets. Interest on the Legacy Facility is payable monthly and is charged in accordance with the Partnership s selection of a LIBOR rate plus 1.25% to 1.875%, or prime rate up to prime rate plus 0.375%, dependent on the percentage of the borrowing base which is drawn. On March 15, 2006, Legacy borrowed $65.8 million from the new lending group as part of the Legacy Formation. On May 3, 2007, Legacy s bank group increased Legacy s borrowing base to $150 million as part of the semi-annual re-determination. On October 24, 2007, the Legacy Facility was amended, increasing the borrowing base to $225 million and the borrowing capacity to $500 million. Pursuant to this amendment, interest on debt outstanding is charged based on Legacy s selection of a LIBOR rate plus 1.00% to 1.75%, or the alternate base rate which equals the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.25%.

On January 18, 2007, Legacy closed its initial public offering of 6,900,000 units representing limited partner interests at an initial public offering price of $19.00 per unit. Net proceeds to the partnership after underwriting discounts and estimated offering expenses were approximately $122 million, all of which was used to repay all indebtedness outstanding under the Legacy Facility and for general partnership purposes.

As of December 31, 2007, Legacy had outstanding borrowings of $110 million at an interest rate of 6.50%. Thus, Legacy had approximately $115 million of availability remaining. For the year ended December 31, 2007, Legacy paid $5,090,148 of interest expense on the Legacy Facility. The Legacy Facility contains certain loan covenants requiring minimum financial ratio coverages, involving the current ratio and EBITDA to interest expense. At December 31, 2007, Legacy was in compliance with all aspects of the Legacy Facility.

Long-term debt consists of the following at December 31, 2006 and 2007:

	December 31,	
	2006	2007
Legacy facility-due March 2010	$ 115,800,000	$ 110,000,000

(4) Acquisitions

PITCO Acquisition

On September 14, 2005, MBN Properties LP purchased oil and natural gas producing properties located in the Permian Basin from PITCO and its affiliates for $66,151,723 (the PITCO Acquisition), subject to post-closing adjustments of approximately $2.8 million. The all cash acquisition was funded from borrowings of $33,750,000 under MBN Properties LP s existing credit facility and from loans from MPL and the Brothers Group (see Note 3). Including direct expenses associated with the PITCO acquisition, MBN Properties LP has recorded a purchase price of approximately $63.9 million, all of which has been allocated to the oil and natural gas properties purchased. In addition, MBN Properties LP has recorded a $445,000 asset retirement obligation (ARO) and related ARO asset under the guidelines of FAS 143. The results of operations from the properties acquired in the PITCO acquisition have been included in Legacy s statements of operations beginning September 14, 2005.

Legacy Formation Acquisition

On March 15, 2006, LRLP completed a private equity offering in which it issued 5,000,000 limited partnership units at a gross price of $17.00 per unit, netting $76.8 million after initial purchaser s discount, placement agent fees and expenses. Simultaneous with the completion of this offering, Legacy purchased the oil and natural gas properties of the Moriah Group, Brothers Group, H2K Holdings Ltd. and the Charitable Support Foundations, Inc. and its affiliates. Legacy also purchased the oil and natural gas properties owned by MBN Properties, LP. In the case

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the Moriah Group, the Brothers Group and H2K Holdings Ltd. those entities exchanged their oil and natural gas properties for limited partnership units. The purchase of the oil and natural gas properties owned by the charitable foundations was solely for cash of $7.7 million. The owners of the Moriah Group, the Brothers Group and H2K Holdings Ltd. (the Founding Investors) exchanged 4.4 million of their units for $69.9 million in cash. The Moriah Group has been treated as the acquiring entity in the Legacy Formation. Accordingly, the accounts of the businesses acquired from the Moriah Group have been reflected retroactively at carryover basis in the consolidated financial statements, and the units issued to acquire them have been accounted for as a recapitalization. The net assets of the other businesses acquired and the units issued in exchange for them have been reflected at fair value and included in the statement of operations from the date of acquisition. With the exception of its assumption of liabilities associated with the oil and natural gas swaps it acquired, the other depreciable assets of the Brothers Group (office furniture and equipment and vehicles) and certain unamortized deferred financing costs of the Moriah Group, LRLP did not acquire any other assets or liabilities of the Moriah Group, the Brothers Group, H2K Holdings Ltd. or the Charitable Support Foundations, Inc. and its affiliates. The removal of the other assets and liabilities of the Moriah Group was reflected as a deemed dividend in Legacy s December 31, 2006 consolidated statement of unitholders equity.

The following table sets forth the units issued in the Legacy Formation transaction:

	Number of Units
MPL	7,334,070
DAB Resources, Ltd.	859,703
Moriah Group	8,193,773
Brothers Group	6,200,358
H2K Holdings Ltd.	83,499
MBN Properties LP	3,162,438
LRLP units	600,000
Total units issued at Legacy Formation	18,240,068

In addition to the 18,240,068 units issued at Legacy Formation, 52,616 restricted management units were issued to employees of Legacy concurrent with, but not as a part of, the Legacy Formation (Note 13).

The following table sets forth the purchase price of the oil and natural gas properties purchased from the Brothers Group, H2K Holdings Ltd. and three charitable foundations, which included the assumption of liabilities associated with oil and natural gas swaps as of March 14, 2006:

	Number of Units at $17.00 per Unit	Purchase Price of Assets Acquired
Brothers Group	6,200,358	$ 105,406,069

H2K Holdings Ltd.	83,499		1,419,483
Cash paid to three charitable foundations			7,682,854
Total purchase price before liabilities assumed			114,508,406
Plus:			
Oil and natural gas swap liabilities assumed			3,147,152
Asset retirement obligations incurred			1,467,241
Less:			
Office furniture, equipment and vehicles acquired			(107,275)
Total purchase price allocated to oil and natural gas properties acquired		$	119,015,524

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition to the 3,162,438 common units issued to MBN Properties LP as part of the Legacy Formation transaction, LRLP paid $65.3 million in cash to MBN Properties LP to acquire that portion of the oil and natural gas properties of MBN Properties LP it did not already own by virtue of the Moriah Group s ownership of a 46.22% limited partnership interest in MBN Properties LP. In addition, LRLP paid $1,980,468 to MBN Management LLC to reimburse expenses incurred by that entity in anticipation of the Legacy Formation. The following table sets forth the calculation of the step-up of oil and natural gas property basis with respect to this interest acquired:

	Number of Units at $17.00 per Unit	Purchase Price of Assets Acquired
Units issued to MBN Properties LP	3,162,438	$ 53,761,446
Cash paid to MBN Properties LP		65,300,000
Total purchase price before liabilities assumed		119,061,446
Plus:		
Oil and natural gas swap liabilities assumed		2,539,625
ARO liabilities assumed		453,913
Less:		
Net book value of other property and equipment on MBN Properties LP at March 14, 2006		(39,056)
		122,015,928
Less:		
Net book value of oil and gas assets on MBN Properties LP at March 14, 2006		(62,990,390)
Purchase price in excess of net book value of assets		59,025,538
Less:		
Share already owned by Moriah via consolidation of MBN Properties LP	46.22%	(27,281,604)
Non-controlling interest share to record(a)		31,743,934
Plus:		
Elimination of deferred financing costs related to non-controlling interests share of MBN Properties LP		164,202
Reimbursement of Brothers Group s share of MBN Management LLC losses from inception through March 14, 2006		780,239

	Number of Units at $17.00 per unit	Purchase Price of Assets Acquired

MBN Properties LP purchase price to allocate to oil and natural gas properties		$	32,688,375
Units related to purchase of non-controlling interest(a)	1,867,290		
Units related to interest previously owned by Moriah Group	1,295,148		
Total units issued to MBN Properties LP	3,162,438		

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Larron Acquisition

On June 29, 2006, Legacy purchased a 100% working interest and an approximate 82% net revenue interest in producing leases located in the Farmer Field for $5,700,000. The conveyance of the leases is effective April 1, 2006. The $5.6 million net purchase price was allocated with $4.6 million recorded as lease and well equipment and $1.0 million of leasehold costs. Asset retirement obligations in the amount of $328,867 were recognized in connection with this acquisition. The operations of these Farmer Field properties are included from their acquisition on June 29, 2006 in Legacy s statement of operations for the year ended December 31, 2006.

South Justis Unit Acquisition

On June 29, 2006, Legacy purchased Henry Holding LP s 15.0% working interest and a 13.1% net revenue interest in the South Justis Unit (SJU), two leases not in the unit, each with one well, adjacent to the SJU and the right to operate these properties. The stated purchase price was $14 million cash plus the issuance of 138,000 units on June 29, 2006 and 8,415 units on November 10, 2006 at their estimated fair value of $17.00 per unit ($2,346,000 and $143,055, respectively) less final adjustments of approximately $624,000. The effective date of Legacy s ownership was May 1, 2006. The operating results from this acquisition have been included from July 1, 2006. The properties acquired are located in Lea County, New Mexico where Legacy owns other producing properties. Legacy has been elected operator of the SJU following the closing of the transaction, which entitles Legacy to a contractual overhead reimbursement of approximately $127,500 per month from its partners in the SJU. The $15.9 million net purchase price was allocated with $2.9 million recorded as lease and well equipment, $6.0 million of leasehold costs and $7.0 million capitalized as an intangible asset relating to the contract operating rights. The capitalized operating rights will be amortized over the estimated total well months the wells in the SJU are expected to be operated. Asset retirement obligations in the amount of $137,453 were recognized in connection with this acquisition. The operations of the South Justis Unit are included from the acquisition on June 29, 2006 in Legacy s statement of operations for the year ended December 31, 2006.

Kinder Morgan Acquisition

On July 31, 2006, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Kinder Morgan for a net purchase price of $17.2 million. The effective date of this purchase was July 1, 2006. The $17.2 million purchase price was allocated with $4.1 million recorded as lease and well equipment and $13.1 million of leasehold costs. Asset retirement obligations of $1,383,180 were recorded in connection with this acquisition. The operations of these Kinder Morgan Acquisition properties are included from their acquisition on July 31, 2006 in Legacy s statement of operations for the year ended December 31, 2006.

Binger Acquisition

On April 16, 2007, Legacy purchased certain oil and natural gas properties and other interests in the East Binger (Marchand) Unit in Caddo County, Oklahoma from Nielson & Associates, Inc. for a net purchase price of $44.2 million (Binger Acquisition). The purchase price was paid with the issuance of 611,247 units valued at $15.8 million and $28.4 million paid in cash. The effective date of this purchase was February 1, 2007. The $44.2 million purchase price was allocated with $14.7 million recorded as lease and well equipment, $29.4 million of leasehold costs and $0.1 million as investment in equity method investee related to the 50% interest acquired in

Binger Operations, LLC. Asset retirement obligations of $184,636 were recorded in connection with this acquisition. The operations of these Binger Acquisition properties have been included from their acquisition on April 16, 2007.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Ameristate Acquisition

On May 1, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Ameristate Exploration, LLC for a net purchase price of $5.2 million (Ameristate Acquisition). The effective date of this purchase was January 1, 2007. The $5.2 million purchase price was allocated with $0.5 million recorded as lease and well equipment and $4.7 million of leasehold costs. Asset retirement obligations of $51,414 were recorded in connection with this acquisition. The operations of these Ameristate Acquisition properties have been included from their acquisition on May 1, 2007.

TSF Acquisition

On May 25, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Terry S. Fields for a net purchase price of $14.7 million (TSF Acquisition). The effective date of this purchase was March 1, 2007. The $14.7 million purchase price was allocated with $1.8 million recorded as lease and well equipment and $12.9 million of leasehold costs. Asset retirement obligations of $99,094 were recorded in connection with this acquisition. The operations of these TSF Acquisition properties have been included from their acquisition on May 25, 2007.

Raven Shenandoah Acquisition

On May 31, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Raven Resources, LLC and Shenandoah Petroleum Corporation for a net purchase price of $13.0 million (Raven Shenandoah Acquisition). The effective date of this purchase was May 1, 2007. The $13.0 million purchase price was allocated with $6.0 million recorded as lease and well equipment and $7.0 million of leasehold costs. Asset retirement obligations of $378,835 were recorded in connection with this acquisition. The operations of these Raven Shenandoah Acquisition properties have been included from their acquisition on May 31, 2007.

Raven OBO Acquisition

On August 3, 2007, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin from Raven Resources, LLC and private parties for a net purchase price of $20.0 million (Raven OBO Acquisition). The effective date of this purchase was July 1, 2007. The $20.0 million purchase price was allocated with $1.6 million recorded as lease and well equipment and $18.4 million of leasehold costs. Asset retirement obligations of $224,329 were recorded in connection with this acquisition. The operations of these Raven OBO Acquisition properties have been included from their acquisition on August 3, 2007.

TOC Acquisition

On October 1, 2007, Legacy purchased certain oil and natural gas properties located in the Texas Panhandle from The Operating Company, et al, for a net purchase price of $60.6 million (TOC Acquisition). The effective date of this purchase was September 1, 2007. The $60.6 million purchase price was allocated with $23.7 million recorded as lease and well equipment and $36.9 million of leasehold costs. Asset retirement obligations of $1.6 million were recorded in connection with this acquisition. The operations of these TOC Acquisition properties have been included from their acquisition on October 1, 2007.

Summit Acquisition

Also on October 1, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Summit Petroleum Management Corporation for a net purchase price of $13.5 million (Summit Acquisition). The effective date of this purchase was September 1, 2007. The $13.5 million purchase price was allocated with $2.1 million recorded as lease and well equipment and $11.3 million as leasehold cost. Asset retirement

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

obligations of $128,705 were recorded in connection with this acquisition. The operations of these Summit Acquisition properties have been included from their acquisition on October 1, 2007.

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the PITCO, Formation Transactions, Farmer Field, South Justis Unit, and Kinder Morgan acquisitions had occurred on January 1, 2005. The table also reflects the unaudited pro forma results of operations as though the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisitions had each occurred on January 1, 2006 and 2007. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	December 31, 2005	December 31, 2006	December 31, 2007
	(Dollars in thousands, except per unit data)		
Revenues	$ 64,128	$ 115,414	$ 133,628
Net income (loss)	$ 6,295	$ 12,844	$ (53,261)
Earnings per unit basic:			
Income from continuing operations	$ 0.34	$ 0.68	$ (2.02)
Net income	$ 0.34	$ 0.68	$ (2.02)
Earnings per unit diluted:			
Income from continuing operations	$ 0.34	$ 0.68	$ (2.02)
Net income	$ 0.34	$ 0.68	$ (2.02)
Units used in computing earnings per unit:			
basic	18,386,482	19,004,035	26,331,107
diluted	18,386,482	19,005,627	26,331,107

(5) Partnership Investments

MBN Properties LP, a Delaware limited partnership, and its 1% general partner, MBN Management LLC, a Delaware limited liability company, (collectively the MBN Group) were formed in 2005 to acquire and operate oil and natural gas producing properties in partnership with Brothers Production Properties, Ltd., and certain third party investors. On July 22, 2005, MPL advanced $1,649,132 in the form of $462 of paid in capital (46.2% partnership equity interest) and subordinated notes receivable of $1,648,670 to MBN Properties LP which utilized the capital to fund a deposit with The Prospective Investment and Trading Company, Ltd. (PITCO) and its affiliates for the purchase of oil and natural gas properties described in Note 4 above. On September 13, 2005, MPL advanced MBN Properties LP an additional $17,598,000 under the subordinated note receivable in conjunction with the closing of the PITCO acquisition described in Note 4 above. The subordinated note receivable from MBN Properties LP was due on July 15, 2012 and bore interest payable quarterly at the rate the Moriah Group paid under its New Facility plus 4%. The other investors in MBN Properties, LP loaned money on similar terms. The notes payable to the other investors were not eliminated in consolidation. MPL also advanced $654,099 to fund the expenses of MBN Management LLC, the general partner of MBN Properties LP. Of this amount, $467 was for paid in capital (46.7% partnership equity interest) and the balance of $653,632 was in a subordinated note receivable from MBN Management LLC due July 15, 2012 and bearing interest at 7%. At December 31, 2005, MBN Properties LP had a payable to MBN Management LLC in the amount of $194,907 related to advances made to MBN Properties LP during the period from inception through December 31, 2005. All amounts owned by MBN

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Properties LP and MBN Management LLC to Legacy were repaid on March 15, 2006 in connection with the Formation Transactions.

The following tables reflect condensed balance sheet and net loss information for MBN Management LLC on a gross basis:

	December 31, 2005
Current assets	$ 1,233,338
Other assets	31,899
Total assets	$ 1,265,237
Current liabilities	$ 640,727
Notes payable affiliated entities	1,952,753
Members capital	(1,328,243)
Total liabilities and members capital	$ 1,265,237

	From Inception through December 31, 2005	January 1, 2006 to March 14, 2006
General and administrative expenses	$ (1,278,685)	$ (522,569)
Operating loss	(1,278,685)	(522,569)
Other expense	(50,558)	(21,961)
Net loss	$ (1,329,243)	$ (544,530)

(6) Related Party Transactions

Cary Brown and Dale Brown, as owners of the Moriah Group, and the Brothers Group own a combined non-controlling 4.16% interest as limited partners in the partnership which owns the building that Legacy occupies. Monthly rent is $14,808, without respect to property taxes and insurance. Prior to the Legacy Formation, the Moriah Group s portion of this rent was reimbursed by the Moriah Group to Petroleum Strategies, Inc., an affiliated entity which is owned by Cary Brown and Dale Brown. The lease expires in August 2011.

The Moriah Group did not directly employ any persons or directly incur any office overhead. Substantially all general and administrative services were provided by Petroleum Strategies, Inc. which employed all personnel and paid for all employee salaries, benefits, and office expenses. Petroleum Strategies Inc. charged the Moriah Group for such services in an amount which was intended to be equal to the actual expenses it incurred. Amounts charged were $838,899, $445,267 and $0 for the years ended December 31, 2005, 2006 and 2007, respectively. On April 1, 2006 following the Legacy Formation, certain employees of Petroleum Strategies, Inc. and Brothers Production Company Inc. became employees of Legacy. For the period from March 15, 2006 to December 31, 2006, Brothers Production Company Inc. provided $47,236 of transition administrative services to Legacy.

Legacy uses Lynch, Chappell and Alsup for legal services. Alan Brown, son of Dale Brown and brother of Cary Brown, is a less than ten percent shareholder in this firm. Legacy paid legal fees of $23,472, $40,392 and $127,313 for the years ended December 31, 2005, 2006 and 2007, respectively.

(7) Commitments and Contingencies

From time to time Legacy is a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, Legacy is not currently a party to any proceeding that it believes, if determined in a manner adverse to Legacy, could have a potential material adverse effect on its

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial condition, results of operations or cash flows. Legacy believes the likelihood of such a future event to be remote.

Additionally, Legacy is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of Legacy could be adversely affected.

Legacy has employment agreements with its officers that specify that if the officer is terminated by Legacy for other than cause or following a change in control, the officer shall receive severance pay ranging from 24 to 36 months salary plus bonus and COBRA benefits.

(8) Business and Credit Concentrations

Cash

Legacy maintains its cash in bank deposit accounts, which, at times, may exceed federally insured amounts. Legacy has not experienced any losses in such accounts. Legacy believes it is not exposed to any significant credit risk on its cash.

Revenue and Trade Receivables

Substantially all Legacy s accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact Legacy s overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, Legacy has not experienced significant credit losses on such receivables. No bad debt expense was recorded in 2005, 2006, or 2007. Legacy cannot ensure that such losses will not be realized in the future. A listing of oil and natural gas purchasers exceeding 10% of Legacy s sales is presented in Note 10.

(9) Derivative Financial Instruments

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. While the use of these arrangements limits Legacy s ability to benefit from increases in the price of oil and natural gas, it also reduces Legacy s potential exposure to adverse price movements. Legacy s arrangements, to the extent it enters into any, apply to only a portion of its production, provide only partial price protection against declines in oil and natural gas prices and limit Legacy s potential gains from future increases in prices. None of these instruments are used for trading or speculative purposes.

All of these price risk management transactions are considered derivative instruments and accounted for in accordance with SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities.* These derivative instruments are intended to mitigate a portion of Legacy s price-risk and may be considered hedges for economic purposes but Legacy has chosen not to designate them as cash flow hedges for accounting purposes. Therefore, all derivative instruments are recorded on the balance sheet at fair value with changes in fair value being recorded in current period earnings.

By using derivative instruments to mitigate exposures to changes in commodity prices, Legacy exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes Legacy, which creates repayment risk. Legacy minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the years ended December 31, 2005, 2006, and 2007, Legacy recognized realized and unrealized losses related to its oil, NGL and natural gas derivatives. The impact on net income from hedging activities was as follows:

	December 31, 2005	December 31, 2006	December 31, 2007
Crude oil derivative contract settlements	$ (3,530,651)	$ (6,666,755)	$ (3,627,050)
Natural gas liquid derivative contract settlements			(619,466)
Natural gas derivative contract settlements		6,404,533	4,457,519
Total derivative contract settlements	(3,530,651)	(262,222)	211,003
Unrealized change in fair value oil contracts	(910,738)	4,338,459	(76,484,184)
Unrealized change in fair value natural gas liquid contracts			(3,228,274)
Unrealized change in fair value natural gas contracts	(1,717,476)	5,212,233	(5,654,577)
Total unrealized change in fair value	(2,628,214)	9,550,692	(85,367,035)
Total effect of derivative contracts	$ (6,158,865)	$ 9,288,470	$ (85,156,032)

In June 2005, Legacy paid its counterparty approximately $3.5 million to cancel and reset 2006 oil swaps from $51.31 to $59.38 per barrel. On July 22, 2005 Legacy paid approximately $0.8 million for an option to enter into a $55.00 per barrel oil swap related to the PITCO acquisition that was not exercised.

In September 2006, Legacy paid its counterparty $4 million to cancel and reset oil swaps for 372,000 barrels in 2007 from $60.00 to $65.82 per barrel and for 348,000 barrels in 2008 from $60.50 to $66.44 per barrel.

As of December 31, 2007, Legacy had the following NYMEX West Texas Intermediate crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Calendar Year	Annual Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2008	1,068,449	$ 69.31	$ 62.25 - $86.75
2009	986,413	$ 67.43	$ 61.05 - $86.75
2010	919,445	$ 66.10	$ 60.15 - $86.75
2011	698,640	$ 70.97	$ 67.33 - $86.75
2012	580,800	$ 70.94	$ 67.72 - $86.75

As of December 31, 2007, Legacy had the following NYMEX Henry Hub, ANR-OK and Waha natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	Annual Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2008	2,533,770	$ 8.14	$ 6.85 - $10.58
2009	2,331,470	$ 7.99	$ 6.85 - $10.17
2010	2,065,955	$ 7.73	$ 6.85 - $9.73
2011	788,824	$ 7.25	$ 6.85 - $7.57
2012	493,236	$ 7.16	$ 6.85 - $7.57

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2007, Legacy had the following gas basis swaps in which we receive floating NYMEX prices less a fixed basis differential and pay prices on the floating Waha index, a natural gas hub in West Texas. The prices that we receive for our natural gas sales follow Waha more closely than NYMEX:

Calendar Year	Annual Volumes (MMBtu)	Basis Range per Mcf	
2008	1,422,000	$	(0.84)
2009	1,320,000	$	(0.68)
2010	1,200,000	$	(0.57)

As of December 31, 2007, Legacy had the following Mont Belvieu, Non-Tet OPIS natural gas liquids swaps paying floating natural gas liquids prices and receiving fixed prices for a portion of its future natural gas liquids production as indicated below:

Calendar Year	Annual Volumes (Gal)	Average Price per Gal		Price Range per Gal	
2008	6,458,004	$	1.27	$	0.66-$1.62
2009	2,265,480	$	1.15	$	1.15

On August 29, 2007, Legacy entered into LIBOR interest rate swaps beginning in October of 2007 and extending through November 2011. The swap transaction has Legacy paying its counterparty fixed rates ranging from 4.8075% to 4.82%, per annum, and receiving floating rates on a total notional amount of $54 million. The swaps are settled on a quarterly basis, beginning in January of 2008 and ending in November of 2011.

Legacy accounts for these interest rate swaps pursuant to FAS No. 133 *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement establishes accounting and reporting standards requiring that derivative instruments be recorded at fair market value and included in the balance sheet assets or liabilities.

As the term of Legacy s interest rate swaps extend through November of 2011, a period that extends beyond the term of the credit agreement, which expires on March 15, 2010, Legacy did not specifically designate these derivatives as cash flow hedges, even though they reduce its exposure to changes in interest rates. Therefore, the mark-to-market of these instruments, which amounts to $1.5 million in 2007, is recorded in current earnings. The table below summarizes the interest rate swap position as of December 31, 2007.

	Fixed	Effective	Maturity	Estimated Fair Market Value at December 31,

Notional Amount	Rate	Date	Date		2007
$29,000,000	4.8200%	10/16/2007	10/16/2011	$	(797,823)
$13,000,000	4.8100%	11/16/2007	11/16/2011		(366,241)
$12,000,000	4.8075%	11/28/2007	11/28/2011		(331,698)
Total Fair Market Value				$	(1,495,762)

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) Sales to Major Customers

Legacy operates as one business segment within the Permian Basin region. It sold oil, NGL and natural gas production representing 10% or more of total revenues for the years ended December 31, 2005, 2006 and 2007 as shown below:

	2005	2006	2007
Conoco Phillips	10%	4%	3%
Navajo Crude Oil Marketing	16%	12%	11%
Plains Marketing, LP	18%	14%	13%
Teppco Crude Oil, LP	5%	5%	13%

In the exploration, development and production business, production is normally sold to relatively few customers. Substantially all of the Legacy s customers are concentrated in the oil and natural gas industry and revenue can be materially affected by current economic conditions, the price of certain commodities such as crude oil and natural gas and the availability of alternate purchasers. Legacy believes that the loss of any of its major purchasers would not have a long-term material adverse effect on its operations.

(11) Asset Retirement Obligation

In June 2001, the FASB issued FAS No. 143, which requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which it is incurred and becomes determinable. Under this method, when liabilities for dismantlement and abandonment costs, excluding salvage values, are initially recorded, the carrying amount of the related oil and natural gas properties is increased. The fair value of the ARO asset and liability is measured using expected future cash outflows discounted at Legacy s credit-adjusted risk-free interest rate. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted over the useful life of the related asset.

The following table reflects the changes in the ARO during the years ended December 31, 2005, 2006, and 2007.

	December 31,		
	2005	2006	2007
Asset retirement obligation beginning of period	$ 1,952,866	$ 2,302,147	$ 6,492,780
Liabilities incurred in Legacy formation		1,467,241	
Liabilities incurred with properties acquired	446,901	1,888,954	3,033,501
Liabilities incurred with properties drilled		22,882	114,317
Liabilities settled during the period	(53,852)	(213,343)	(372,611)
Current period accretion	109,429	242,432	470,002
Current period revisions to accretion expense	(163,281)		
Current period revisions to oil and natural gas properties	10,084	782,467	6,181,660

Asset retirement obligation end of period	$ 2,302,147	$ 6,492,780	$ 15,919,649

The discount rate used in calculating the ARO was 6.0% at December 31, 2005, 7.25% at December 31, 2006 and 6.47% at December 31, 2007. These rates approximate Legacy s borrowing rates.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(12) Earnings (Loss) Per Unit

The following table sets forth the computation of basic and diluted net earnings (loss) per unit (dollars in thousands, except per unit):

	December 31, 2005	December 31, 2006	December 31, 2007
Income (loss) available to unitholders	$ 5,859	$ 4,357	$ (55,662)
Weighted average number of units outstanding	9,488,921	16,567,287	26,155,439
Effect of dilutive securities:			
Unit options			
Restricted units		1,592	
Weighted average units and potential units outstanding	9,488,921	16,568,879	26,155,439
Basic earnings per unit	$ 0.62	$ 0.26	$ (2.13)
Diluted earnings per unit	$ 0.62	$ 0.26	$ (2.13)

At December 31, 2006, options to purchase 260,000 units at exercise prices ranging from $17.00 to $17.25 per unit were outstanding, but were not included in the computation of diluted earnings per share due to their anti-dilutive effect. At December 31, 2007, 45,078 restricted units and options to purchase 252,306 units at exercise prices ranging from $17.00 to $27.84 per unit were outstanding, but were not included in the computation of diluted earnings per share due to their anti-dilutive effect.

(13) Unit-Based Compensation

Long Term Incentive Plan

Concurrent with the Formation Transaction on March 15, 2006, a Long-Term Incentive Plan (LTIP) for Legacy was created and Legacy adopted SFAS No. 123(R), Share-Based Payment. Legacy adopted the Legacy Reserves LP Long-Term Incentive Plan for its employees, consultants and directors, its affiliates and its general partner. The awards under the long-term incentive plan may include unit grants, restricted units, phantom units, unit options and unit appreciation rights. The long-term incentive plan permits the grant of awards covering an aggregate of 2,000,000 units. As of December 31, 2007 grants of awards net of forfeitures covering 505,576 units have been made, comprised of 422,460 unit options and unit appreciation rights awards, 65,116 restricted unit awards and 18,000 phantom unit awards. The LTIP is administered by the compensation committee of the board of directors of its general partner.

SFAS No. 123(R), Share-Based Payment requires companies to measure the cost of employee services in exchange for an award of equity instruments based on a grant-date fair value of the award (with limited exceptions), and that cost must generally be recognized over the-vesting period of the award. Prior to April of 2007, Legacy utilized the equity method of accounting as described in SFAS No. 123(R) to recognize the cost associated with unit options. However, SFAS No. 123(R) stipulates that if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if entity usually settles in cash whenever an employee asks for cash settlement, the entity is settling a substantive liability rather than repurchasing an equity instrument.

The initial vesting of options occurred on March 15, 2007, with initial option exercises occurring in April 2007. At the time of the initial exercise Legacy settled these exercises in cash and determined it was likely to do so for future option exercises. Consequently, in April 2007, Legacy began accounting for unit option grants by utilizing the liability method as described in SFAS No. 123(R). The liability method requires companies to measure the cost

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the employee services in exchange for a cash award based on the fair value of the underlying security at the end of the period. Compensation cost is recognized based on the change in the liability between periods.

Unit Options and Unit Appreciation Rights

During the year ended December 31, 2006, Legacy issued 273,000 unit option awards to officers and employees which vest ratably over a three-year period. During the year ended December 31, 2007, Legacy issued 113,000 unit option awards to employees which vest ratably over a three-year period. During the year ended December 31, 2007, Legacy issued 66,116 unit option awards which cliff-vest at the end of a three-year period. All options granted in 2007 expire five years from the grant date and are exercisable when they vest.

For the year ended December 31, 2007, Legacy recorded $826,406 of compensation expense based on its use of the Black Scholes model to estimate the December 31, 2007 fair value of these unit option awards and the exercise date fair value of options exercised during the period. As of December 31, 2007, there was a total of $919,028 of unrecognized compensation costs related to the un-exercised and non-vested portion of these unit option awards. At December 31, 2007, this cost was expected to be recognized over a weighted-average period of 2.0 years. Compensation expense is based upon the fair value as of December 31, 2007 and is recognized as a percentage of the service period satisfied. Since Legacy is a newly public company and has minimal trading history, it has used an estimated volatility factor of approximately 41% based upon a representative group of publicly-traded companies in the energy industry and employed the fair value method to estimate the December 31, 2007 fair value to be realized as compensation cost based on the percentage of the service period satisfied. In the absence of historical data, Legacy has assumed an estimated forfeiture rate of 5%. As required by SFAS No. 123(R), the Partnership will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $1.80 per unit.

A summary of option activity for the year ended December 31, 2007 is as follows:

	Units	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term
Outstanding at January 1, 2007	260,000	$ 17.01	
Granted	179,116	$ 23.09	
Exercised	(23,038)	$ 17.00	
Forfeited	(16,656)	$ 17.09	
Outstanding at December 31, 2007	399,422	$ 19.73	3.6 years
Options exercisable at December 31, 2007	62,800	$ 17.04	3.3 years

The following table summarizes the status of the Partnership s non-vested stock options since January 1, 2007:

	Non-Vested Options	
	Number of Units	Weighted-Average Fair Value
Non-vested at January 1, 2007	260,000	$ 2.62
Granted	179,116	3.40
Vested Unexercised	(62,800)	4.65
Vested Exercised	(23,038)	10.14
Forfeited	(16,656)	9.56
Non-vested at December 31, 2007	336,622	$ 4.09

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Legacy has used a weighted-average risk free interest rate of 3.5% in its Black Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at December 31, 2007. Expected life represents the period of time that options are expected to be outstanding and is based on the Partnership s best estimate. The following table represents the weighted average assumptions used for the Black-Scholes option-pricing model:

	Year Ended December 31, 2007
Expected life (years)	5
Annual interest rate	3.5%
Annual distribution rate per unit	$ 1.80
Volatility	41%

Restricted and Phantom Units

As described below, Legacy has also issued phantom units under the LTIP. Because Legacy s current intent is to settle these awards in cash, Legacy is accounting for the phantom units by utilizing the liability method.

On June 27, 2007, Legacy granted 3,000 phantom units to an employee which vest ratably over a five year period, beginning at the date of grant. On July 16, 2007, Legacy granted 5,000 phantom units to an employee which vest ratably over a five year period, beginning at the date of grant. On December 3, 2007, Legacy granted 10,000 phantom units to an employee. The phantom units awarded vest ratably over a three year period, beginning on the date of grant. In conjunction with these grants, the employees are entitled to dividend equivalent rights (DERs) for unvested units held at the date of dividend payment. Compensation expense related to the phantom units and associated DERs was $52,273 for the year ended December 31, 2007.

On August 20, 2007, the board of directors of Legacy s general partner, upon recommendation from the Compensation Committee, approved phantom unit awards which may award up to 175,000 units to five key executives of Legacy based on achievement of targeted annual MLP distribution levels over a base amount of $1.64 per unit. These awards are to be determined annually based solely on the annualized level of per unit distributions for the fourth quarter of each calendar year and subsequently vested over a 3 year period. There is a range of 0% to 100% of the distribution levels at which the performance condition may be met. For each quarter, management recommends to the board an appropriate level of per unit distribution based on available cash of Legacy. This level of distribution is approved by the board subsequent to management s recommendation. Probable issuances for the purposes of calculating compensation expense associated therewith are determined based on management s determination of probable future distribution levels for interim periods and based on actual distributions for annual periods as described above. Expense associated with vesting is recognized over the period from the date vesting becomes probable to the end of the three year vesting period beginning at each year end. Compensation expense related to the phantom units was $44,381 for the year ended December 31, 2007.

On March 15, 2006, Legacy issued 52,616 units of restricted unit awards to two employees. The restricted units awarded vest ratably over a three-year period, beginning on the date of grant. On May 5, 2006, Legacy issued 12,500 units of restricted unit awards to an employee. The restricted units awarded vest ratably over a five-year period, beginning on the date of grant. Compensation expense related to restricted units was $270,039 and $340,656 for the years ended December 31, 2006 and 2007, respectively. As of December 31, 2007, there was a total of $496,275 of unrecognized compensation costs related to the non-vested portion of these restricted units. At December 31, 2007, this cost was expected to be recognized over a weighted-average period of 1.8 years.

On May 1, 2006, Legacy granted and issued 1,750 units to each of its five non-employee directors as part of their annual compensation for serving on Legacy s board. The value of each unit was $17.00 at the time of grant. On November 26, 2007, Legacy granted and issued 1,750 units to each of its four non-employee directors as part of their annual compensation for serving on Legacy s board. The value of each unit was $21.32 at the time of grant.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(14) Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities

Costs incurred by Legacy in oil and natural gas property acquisition and development are presented below:

	Year Ended December 31,		
	2005	**2006**	**2007**
Development costs	$ 1,958,455	$ 17,325,052	$ 22,967,534
Exploration costs			
Acquisition costs:			
Proved properties	65,405,917	187,006,693	200,399,637
Unproved properties	2,928		
Total acquisition, development and exploration costs	$ 67,367,300	$ 204,331,745	$ 223,367,171

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, and to provide facilities to extract, treat, and gather natural gas.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(15) Net Proved Oil and Natural Gas Reserves (Unaudited)

The proved oil and natural gas reserves of Legacy have been estimated by an independent petroleum engineer, LaRoche Petroleum Consultants, Ltd., as of December 31, 2005, 2006 and 2007. These reserve estimates have been prepared in compliance with the Securities and Exchange Commission rules based on year-end prices and costs. The table below includes the reserves associated with the PITCO acquisition in September 2005 which is reflected in the December 31, 2005 balances, the Legacy Formation acquisition in March 2006, the Farmer Field and South Justis acquisitions in June 2006 and the Kinder Morgan acquisition in July 2006 which are reflected in the December 31, 2006 balances and the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisitions which are reflected in the December 31, 2007 balances. An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, is shown below:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)
Total Proved Reserves:			
Balance, December 31, 2004	4,109		10,470
Purchases of minerals-in- place	3,541		12,800
Revisions of previous estimates due to infill drilling, recompletion s and stimulations	794		1,258
Revisions of previous estimates due to prices and performance	28		956
Production	(354)		(1,027)
Balance, December 31, 2005(a)	8,118		24,457
Purchases of minerals-in- place	6,352		11,871
Extensions and discoveries	75		207
Revisions of previous estimates due to infill drilling, recompletions and stimulations	233		494
Revisions of previous estimates due to prices and performance	(657)		(2,296)
Production	(749)		(2,200)
Balance, December 31, 2006	13,372		32,533
Purchases of minerals-in-place	6,367	3,971	19,417
Sales of minerals-in- place	(1)		(2)
Revisions from drilling and recompletion s	220		386
Revisions of previous estimates due to price and performance	810	180	1,578
Production	(1,179)	(126)	(3,052)
Balance, December 31, 2007	19,589	4,025	50,860

Proved Developed Reserves:

December 31, 2004	4,109		10,470
December 31, 2005	6,380		20,618
December 31, 2006	11,132		28,126
December 31, 2007	17,434	3,954	45,455

(a) Includes 3.2 MMBls of oil and 13.0 Bcf of natural gas held by MBN Properties, LP of which 1.7 MMBls and 7.0 Bcf of natural gas was owned by the non-controlling interest.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(16) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves (Unaudited)

Summarized in the following table is information for Legacy inclusive of MBN/PITCO acquisition properties from September 2005, the Legacy Formation acquisition properties from March 2006, the Farmer Field and South Justis acquisition properties from June 2006 and the Kinder Morgan acquisition properties from July 2006, and the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisition properties in 2007 with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Future cash inflows are computed by applying year-end prices relating to the Legacy s proved reserves to the year-end quantities of those reserves. Future production, development, site restoration, and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Legacy s future federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on their share of Legacy s taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary, as discussed in Note 1(f), have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure.

	December 31,		
	2005(a)	2006	2007
	(Thousands)		
Future production revenues	$ 684,021	$ 947,914	$ 2,431,492
Future costs:			
Production	(242,796)	(387,238)	(925,450)
Development	(27,609)	(43,419)	(68,745)
Future net cash flows before income taxes	413,616	517,257	1,437,297
10% annual discount for estimated timing of cash flows	(221,619)	(276,694)	(746,759)
Standardized measure of discounted net cash flows	$ 191,997	$ 240,563	$ 690,538

(a) Includes $93.0 million of standardized measure held by MBN Properties LP of which $50.2 million was owned by the non-controlling interest.

The Standardized Measure is based on the following oil and natural gas prices realized over the life of the properties at the wellhead as of the following dates:

December 31,

	2005	2006	2007
Oil (per Bbl)	$ 57.64	$ 56.73	$ 91.96
Natural Gas (per Mcf)	$ 8.82	$ 5.82	$ 6.39

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows which reflects the PITCO acquisition in 2005, the Legacy Formation in 2006, the Farmer Field, South Justis and the Kinder Morgan acquisitions in 2006 and the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisitions in 2007:

	Year Ended December 31,		
	2005	2006	2007
	(Dollars in thousands)		
Increase (decrease):			
Sales, net of production costs	$ (17,532)	$ (40,113)	$ (77,260)
Net change in sales prices, net of production costs	36,574	(60,531)	178,972
Changes in estimated future development costs	(21,401)	4,582	1,426
Extensions and discoveries, net of future production and development costs		2,723	
Revisions of previous estimates due to infill drilling, recompletions and stimulations	19,319	7,919	7,347
Revisions of previous quantity estimates due to prices and performance	3,156	(12,232)	4,273
Previously estimated development costs incurred	(178)	9,517	7,345
Purchases of minerals-in place	102,289	127,009	300,907
Ownership interest corrections			1,480
Sales of minerals in place			(22)
Other	4,458	(2,971)	2,093
Accretion of discount	4,955	12,663	23,414
Net increase	131,640	48,566	449,975
Standardized measure of discounted future net cash flows:			
Beginning of year	60,357	191,997	240,563
End of year	$ 191,997	$ 240,563	$ 690,538

The data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts.

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) Selected Quarterly Financial Data (Unaudited)

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2007				
Revenues:				
Oil sales	$ 12,301	$ 16,653	$ 22,442	$ 31,905
Natural gas liquids sales	105	1,072	1,714	4,611
Natural gas sales	3,526	5,010	5,241	7,656
Total revenues	15,932	22,735	29,397	44,172
Expenses:				
Oil and natural gas production	4,739	6,088	7,581	8,721
Production and other taxes	994	1,481	1,886	3,528
General and administrative	1,827	2,769	1,443	2,353
Depletion, depreciation, amortization and accretion	5,295	6,811	6,960	9,349
Impairment of long-lived assets	90	190	950	1,974
Loss on disposal of assets		231	156	140
Total expenses	12,945	17,570	18,976	26,065
Operating Income	2,987	5,165	10,421	18,107
Interest income	104	47	54	116
Interest expense	(625)	(893)	(1,905)	(3,695)
Equity in income of partnership		11	30	36
Realized gain (loss) on oil, NGL and natural gas swaps	2,466	1,362	408	(4,025)
Unrealized loss on oil, NGL and natural gas swaps	(9,689)	(7,855)	(6,844)	(60,979)
Other		1		(130)
Net income (loss) before income taxes	(4,757)	(2,162)	2,164	(50,570)
Income taxes				(337)
Net income (loss)	$ (4,757)	$ (2,162)	$ 2,164	$ (50,907)
Net income (loss) per share basic and diluted	$ (0.19)	$ (0.08)	$ 0.08	$ (1.81)
Production volumes:				
Oil (MBbl)	228	273	312	365

Natural Gas Liquids (Mgal)	104	856	1,345	2,991
Natural Gas (MMcf)	588	718	801	945
Total (Mboe)	329	413	478	594

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2006				
Revenues:				
Oil sales	$ 7,440	$ 11,800	$ 13,204	$ 12,907
Natural gas sales	2,995	3,588	4,239	3,624
Total revenues	10,435	15,388	17,443	16,531
Expenses:				
Oil and natural gas production	2,677	3,186	4,297	5,778
Production and other taxes	738	943	1,030	1,035
General and administrative(a)	956	1,253	1,057	426
Dry hole costs				
Depletion, depreciation, amortization and accretion	2,388	4,967	5,346	5,693
Impairment of long-lived assets			8,573	7,540
Loss on disposal of assets				42
Total expenses	6,759	10,349	20,303	20,514
Operating Income	3,676	5,039	(2,860)	(3,983)
Interest income	33	5	55	36
Interest expense	(1,445)	(1,210)	(1,857)	(2,133)
Realized gain (loss) on oil, NGL and natural gas swaps	1,398	548	(4,128)	1,920
Unrealized gain (loss) on oil, NGL and natural gas swaps	(5,294)	(9,724)	22,734	1,835
Other	(303)			14
Net income (loss)	$ (1,935)	$ (5,342)	$ 13,944	$ (2,311)
Net income (loss) per share basic and diluted	$ (0.17)	$ (0.29)	$ 0.76	$ (0.13)
Production volumes:				
Oil (MBbl)	129	184	203	233
Natural Gas (MMcf)	434	594	571	601
Total (Mboe)	201	283	298	333

(a)

General and administrative expenses for the quarter ended December 31, 2006 reflect an adjustment to reverse certain accruals which had been recorded during the first three quarters and were not deemed necessary.

(18) Subsequent Events

On January 23, 2008, the board of directors of Legacy s general partner declared a $0.45 per unit cash distribution for the quarter ended December 31, 2007 to all unitholders of record on February 4, 2008. This distribution was paid on February 14, 2008.

On March 13, 2008, Legacy entered into a definitive purchase agreement to acquire certain oil and natural gas producing properties from a third party for an aggregate purchase price of $82 million, subject to purchase price adjustments. If certain conditions are met, Legacy intends to pay at closing a portion of the purchase price with newly issued units, reducing the cash payment to $55 million, which amount will be subject to closing adjustments.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The properties are located in the Permian Basin of West Texas and Southeast New Mexico, Kansas and Oklahoma. The acquisition is subject to customary closing conditions and is expected to close by April 30, 2008. This acquisition will be accounted for as a purchase of oil and natural gas assets.

On March 13, 2008, Legacy entered into NYMEX WTI Oil swaps and Waha natural gas swaps related to this announced acquisition along with increasing our natural gas fixed price swap exposure on our existing assets in 2011 and 2012. The following tables set forth these new swaps.

The new NYMEX WTI oil swaps are as follows:

Time Period Calendar Contracts	Swap Volumes (Bbls.)	Contract Oil Price ($/Bbl)
June-Dec. 2008	90,300	$ 101.47
2009	145,200	$ 101.47
2010	134,400	$ 101.47
2011	124,800	$ 101.47
2012	116,400	$ 101.47
Total	611,100	$ 101.47

Swaps are tabulated below for natural gas fixed price swaps indexed to the Waha hub in West Texas. The Waha hub trades at a discount range of approximately $0.55 $1.10 to the NYMEX Henry Hub natural gas index. The natural gas prices that we receive for our natural gas sales follow Waha more closely than the NYMEX Henry Hub index.

Time Period Calendar Contracts	Swap Volumes (MMBtu)	Contract Natural Gas Price ($/MMBtu)
June-Dec. 2008	253,463	$ 8.70
2009	399,372	$ 8.70
2010	364,404	$ 8.70
2011	951,792	$ 8.70
2012	719,400	$ 8.70
Total	2,688,431	$ 8.70