LEGACY RESERVES LP
Form 10-K
February 23, 2012

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

Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

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 (State or other jurisdiction of incorporation or organization)	16-1751069 (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 þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes 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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 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 þ Accelerated filer o Non-accelerated filer o Smaller reporting company o
(Do not check if a smaller reporting company)

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

The aggregate market value of units held by non-affiliates of the registrant was approximately $989.6 million on June 30, 2011, based on $29.69 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

47,920,179 units representing limited partner interests in the registrant were outstanding as of February 22, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant's 2012 annual meeting of unitholders are incorporated by reference into Part III of this annual report on Form 10-K.

LEGACY RESERVES LP

Table of Contents

Table of Contents

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.

Hydrocarbons. Oil, NGLs and natural gas are all collectively considered hydrocarbons.

Liquids. Oil and NGLs.

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.

MGal. One thousand gallons of natural gas liquids or other liquid hydrocarbons.

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 and condensate.

Table of Contents

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 PDNPs. Proved oil and natural gas reserves that are developed behind pipe or shut-in or that 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 re-completion prior to the start of production.

Proved reserves. Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

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 undrilled acreage or from existing wells where a relatively major expenditure is required for re-completion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled 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 proven effective by actual tests in the area and in the same reservoir.

Re-completion. 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

Table of Contents

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.

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 current costs and the average annual prices based on the un-weighted arithmetic average of the first-day-of-the-month price for each month) 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 commodity 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 the right to a share of production.

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

Table of Contents

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 locations 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;
- the level of cash distributions to our unitholders;
- 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,” “continue,” 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. 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 unduly rely on them.

Table of Contents

PART I

ITEM 1. BUSINESS

References in this annual report on Form 10-K to “Legacy Reserves,” “Legacy,” “we,” “our,” “us,” or like terms refer to Legac
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, Mid-Continent and Rocky Mountain 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 (“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 support and 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.

Our oil and natural gas production and reserve data as of December 31, 2011 are as follows:

- we had proved reserves of approximately 63.4 MMBoe, of which 68% were oil and natural gas liquids (“NGLs”) and 85% were classified as proved developed producing, 2% were proved developed non-producing, and 13% were proved undeveloped;
- our proved reserves had a standardized measure of $1.1 billion; and
- our proved reserves to production ratio was approximately 12.6 years based on the average daily net production of 13,750 Boe/d (approximately 73% operated) for the three months ended December 31, 2011.

We have grown primarily through two activities: the acquisition of producing oil and natural gas properties and the development of properties in established producing trends. From 2007 through 2011, we completed 93 acquisitions of oil and natural gas properties for a total of approximately $847.3 million, excluding $57.5 million of non-cash asset retirement obligations. These acquisitions of primarily long-lived, oil-weighted assets, along with our ongoing development activities and operational improvements, have allowed us to achieve significant operational and financial growth during this time period.

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 oil, NGL and natural gas derivative transactions.

Operating Regions

Permian Basin. The Permian Basin, one of the largest and most prolific oil and natural gas producing basins in the United States, was discovered in 1921 and extends over 100,000 square miles in West Texas and southeast New Mexico. It is characterized by oil and natural gas fields with long production histories and multiple producing formations. The majority of our producing wells in the Permian Basin are mature oil wells that also produce high-Btu casing head gas with significant NGL content. This region also contains the vast majority of our development inventory, both in terms of proved drilling locations (92% of our proved undeveloped reserves) as well as unproved drilling locations. Our $62 million capital expenditures budget for 2012 is largely focused on the Permian Basin, including our one-rig drilling program that is focused on our proved and unproved Wolfberry drilling locations. The Permian Basin was our only core operating region until we expanded in April 2007 and remains our largest operating region. In 2011, our acquisitions of Permian Basin properties constituted approximately 96% of our $142.2 million of total acquisitions during the year.

Mid-Continent. Our properties in the Mid-Continent region are primarily in the Texas Panhandle and Oklahoma. The vast majority of these properties were acquired through several transactions from April 2007 through October 2008. Our Texas Panhandle wells produce mostly out of the shallow Granite Wash, Brown Dolomite and Red Cave formations. Our operated properties in the Texas Panhandle are mostly mature oil wells that also produce high-Btu casing head gas with significant NGL content, while our non-operated properties are mostly mature, low pressure natural gas wells with high NGL content. Our Texas Panhandle fields contain proved reserves of 6.4 MMBoe (70% liquids), which are approximately 60% of our proved reserves in the Mid-Continent region. Our most notable field in Oklahoma is the East Binger field in Caddo County, Oklahoma. The East Binger Unit, the majority property in the field, is an active miscible nitrogen injection (tertiary recovery) project that produces from the Marchand Sand. This field contains 3.3 MMBoe of proved reserves (84% liquids), which are almost 31% of our proved reserves in the Mid-Continent region. Our remaining properties in the Mid-Continent region are located in multiple counties in Oklahoma, Texas, Kansas and Arkansas.

Rocky Mountain. Almost all of our properties in the Rocky Mountain region are in Wyoming. This area became a core operating region for us after we completed a $125.5 million acquisition in the Big Horn and Wind River Basins in February 2010, which we have complemented with several smaller acquisitions during 2010 and 2011. This region is operated by a team of experienced professionals based in our Cody, Wyoming office. The properties in this region are largely mature oil wells with a natural water drive that produce primarily from the Tensleep, Phosphoria and Minnelusa formations.

Our proved reserves by area are as follows:

Proved Reserves by Operating Region as of December 31, 2011

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)		NGLs(MBbls)	Total (MBoe)	% Liquids		% PDP		% Total	
Permian Basin	28,186	101,176	(a)	802	45,851	63.2	%	82.0	%	72.3	%
Mid-Continent	3,513	18,334		4,000	10,569	71.1	%	98.4	%	16.6	%
Rocky Mountain	6,411	2,452		10	6,830	94.0	%	85.1	%	10.8	%
Other	68	642		22	197	45.7	%	100.0	%	0.3	%
Total	38,178	122,604		4,834	63,447	67.8	%	85.2	%	100.0	%

(a) We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content in those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin are substantially higher than NYMEX Henry Hub natural gas prices due to NGL content.

Acquisition Activities

During the year ended December 31, 2011, we completed 28 acquisitions of oil and natural gas properties with an aggregate purchase price of approximately $142.2 million, excluding $8.3 million of non-cash asset retirement obligations. Based on reserve data prepared internally at the time of these acquisitions reflecting management's expectations of future prices, we added a total of approximately 11.0 MMBoe (9.0 MMBoe based on oil and natural gas prices of $92.71 and $4.12 per Bbl and MMbtu, respectively, as of December 31, 2011) of proved reserves at an average reserve acquisition cost of $12.44 per Boe, ($15.23 per Boe based on December 31, 2011 oil and natural gas prices described above) which excludes associated non-cash asset retirement obligations and $5.5 million of acquisition cost related to undeveloped acreage.

Table of Contents

Development Activities

We have also increased reserves and production through development of our existing and acquired properties. Our development projects are primarily focused on drilling and completing new wells, but also include accessing additional productive formations in existing well-bores, formation stimulation, and artificial lift equipment enhancement, as well as secondary (waterflood) and tertiary (miscible CO_2 and nitrogen) recovery projects.

As of December 31, 2011, we identified 187 gross (126.5 net) proved undeveloped drilling ("PUD") locations, 118 of which were identified and economically viable at December 31, 2010. The table below details the activity in our PUD locations from December 31, 2010 to December 31, 2011:

	Gross Locations	Net Locations	Net Volume (MBoe)
Balance, December 31, 2010	163	103.7	6,420
Drilling activity	(24)	(15.6)	(1,228)
PUDs removed due to performance	(9)	(4.6)	(354)
PUDs removed from future drilling schedule (a)	(12)	(1.8)	(72)
Acquisition activity	3	3.3	131
Additions due to performance	66	41.5	2,849
Other	—	—	295
Balance, December 31, 2011	187	126.5	8,041

(a) These PUD locations were removed from our PUD inventory as a review of our current inventory and future drilling plans indicated that the likelihood of these locations being drilled within the next five years was remote.

As of December 31, 2011, we identified 66 gross (41.9 net) re-completion and fracture stimulation projects.

Excluding acquisitions, we expect to make capital expenditures of approximately $62 million during the year ending December 31, 2012, including, but not limited to, drilling 52 gross (28.0 net) development wells and executing 24 gross (18.1 net) re-completions and fracture stimulations.

Oil and Natural Gas Derivative Activities

Our business 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 66% of our expected oil, NGL and natural gas production from total proved reserves for the year ending December 31, 2012. We have also entered into these derivative contracts for approximately 34%, on average, of our expected oil, NGL and natural gas production from total proved reserves for 2013 through 2016. The majority of our derivative contracts are in the form of fixed price swaps for NYMEX WTI oil, West Texas Waha natural gas, ANR-Oklahoma natural gas and Rocky Mountain CIG natural gas. Additionally, we have sold two call options related to an existing WTI oil swap. These swap related options (“swaptions”) allow the counterparty to extend the contract covering calendar year 2011 to either 2012, 2013 or both. The counterparty exercised the option covering calendar year 2012 on December 30, 2011 and must exercise or decline the option covering calendar year 2013 on December 31, 2012. We have also entered into a NYMEX WTI oil collar that combines a long put option or “floor” with a short call option or “ceiling,” as well as multiple NYMEX WTI oil derivative three-way collar contracts. Each three-way contract combines a short call, a long put and a short put. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also reducing our downside risk. Like a collar, we receive the short call price (net) if the market price is above the short call price, and we receive the market price if the market price is in between the short call and long put prices. Unlike a collar, however, if the market price is below the price of the long put, we receive the long put price only if the market price is still above the short put price. If the market price has fallen below the short put price, we receive the NYMEX WTI market price plus the spread between the short put and the long put prices.

3

Table of Contents

Marketing and Major Purchasers

For the years ended December 31, 2011, 2010 and 2009, Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues to purchasers as detailed in the table below:

	2011	2010	2009
Enterprise (Teppco) Crude Oil, LP	14 %	23 %	22 %
Plains Marketing, LP	11 %	10 %	10 %

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, less 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 any such purchaser could have a detrimental impact on our short-term production volumes and our ability to find substitute purchasers for our production volumes in a timely manner, though we do not believe this would have a long-term material adverse effect on our operations.

Competition

We operate in a highly competitive environment for acquiring properties, securing and retaining trained personnel and marketing oil and natural gas. Many of our competitors possess and employ financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for productive oil and natural gas properties and development projects 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 properties 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.

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. Demand for natural gas and NGLs can be particularly weak in the fall and spring which, coupled with high inventory levels, could result in the shut-in and deferral of production.

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.

4

Table of Contents

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.

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 the 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 drilling 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 were 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 of 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 the 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.

The Oil Pollution Act of 1990, as amended or OPA, which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, owners and operators of facilities that store oil above threshold amounts must develop and implement spill response plans.

Safe Drinking Water Act. Our injection well facilities may be regulated under the Underground Injection Control, or UIC, program established under the Safe Drinking Water Act, or SDWA. The state and federal regulations implementing that program require mechanical integrity testing and financial assurance for wells covered under the program. The federal Energy Policy Act of 2005 amended the UIC provisions of the federal SDWA to exclude hydraulic fracturing from the definition of underground injection. Congress is currently considering bills to repeal this exemption. Further, some states have adopted and others are considering legislation to restrict hydraulic fracturing. Texas and Wyoming have adopted legislation requiring drilling operators conducting hydraulic fracturing activities to publically disclose the chemicals that are used.

Endangered Species Act. Additionally, environmental laws such as the Endangered Species Act, or ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits taking of endangered species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Air Emissions. The Federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the 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 the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency may 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.

In 2007 the U.S. Supreme Court 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 (“GHG”) emissions from stationary sources under certain Clean Air Act programs. In response, on December 7, 2009, the EPA announced its findings that emissions of greenhouse gases present an “endangerment to human health and the environment.” The EPA based this finding on a conclusion that greenhouse gases are contributing to the warming of the earth’s atmosphere and other climate changes. The EPA later adopted regulations that would require a reduction in emissions of greenhouse gases from motor vehicles which became effective on January 2, 2011. The EPA has determined that such regulations trigger permit review for greenhouse gas emissions from certain stationary sources commencing when the motor vehicle standards took effect. The EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs in May 2010. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. The EPA has determined that facilities required to obtain PSD permits for their GHG emissions

Table of Contents

also will be required to reduce those emissions according to “best available control technology” standards for GHG that have yet to be developed. In addition, in late September 2009, the EPA issued its final rule requiring the reporting of greenhouse gases from large greenhouse gas emissions sources in the United States beginning in 2011 for emissions in 2010. Mandatory reporting requirements for oil and natural gas systems were published on November 30, 2010 and require reporting in 2012 for emissions in 2011. 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 products. 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. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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, 2011. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2012. 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 operations.

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;

- 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.

7

Table of Contents

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 regulate and seek to restrict 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 or 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, or the FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC'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 allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, 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, 2011, we had 163 full-time employees, including 17 petroleum engineers, 10 accountants and 6 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 44,932 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 September 2015. In addition to our principal offices, we have a regional office located in Cody, Wyoming that houses engineering and accounting staff for our Wyoming operations.

Table of Contents

Available Information

We make available free of charge on our website, www.legacylp.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such information with, or furnish it to, the SEC.

The information on our website is not, and shall not be deemed to be, a part of this annual report on Form 10-K or incorporated into any of our other filings with the SEC.

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, NGL and natural gas we produce;
- the price at which we are able to sell our oil, NGL and natural gas production;
- the amount and timing of settlements on our commodity and interest rate derivatives;
- 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 may 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.

Table of Contents

Our future growth may be limited because we distribute all of our available cash to our unitholders, and potential future disruptions in the financial markets may prevent us from obtaining the financing necessary for growth and acquisitions.

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. Further, since we 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, potential future disruptions in the global financial markets and any associated severe tightening of credit supply may prevent us from obtaining adequate financing from these sources, and, as a result, our ability to grow, both in terms of additional drilling and acquisitions, will be limited.

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

Higher oil and natural gas prices may increase the rig count and thus the cost of rigs and oil field services necessary to implement our development projects while also decreasing their availability. 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. Decreased availability of drilling equipment and services could significantly impact the planned execution of our scheduled development program.

If commodity prices decline and remain depressed for a prolonged period, a significant portion of our development projects may become uneconomic and cause write downs of the value of our oil and gas properties, which may adversely affect our financial condition and 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. For example, the drastically lower oil and natural gas prices experienced in the fourth quarter of 2008 rendered more than half of the development projects we had planned at such time uneconomic and resulted in a substantial downward adjustment to our estimated proved reserves. Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil and natural gas properties. For example, in 2011 we incurred impairment charges of $24.5 million. In addition, 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.

Fluctuations in price and demand for our natural gas may force us to shut in a significant number of our producing wells, which may adversely impact our revenues and ability to pay distributions to our unitholders.

We are subject to great fluctuations in the prices we are paid for our natural gas due to a number of factors including regional demand, weather, demand for NGLs which are recovered from our gas stream, and new natural gas pipelines such as the REX pipeline from the Rocky Mountains to the Midwest which competes with our natural gas in the Midwest. Drilling in shale resources has developed large amounts of new natural gas supplies that have depressed the prices paid for our natural gas, and we expect the shale resources to continue to be drilled and developed by our competitors. We also face the potential risk of shut-in natural gas due to high levels of natural gas and NGL inventory in storage, weak demand due to mild weather and the effects of any economic downturns on industrial demand. Lack of NGL storage in Mont Belvieu where our West Texas and New Mexico NGLs are shipped for processing could cause the processors of our natural gas to curtail or shut-in our natural gas wells and potentially force us to shut-in oil wells that produce associated natural gas. For example, following Hurricanes Gustav and Ike, when certain Permian Basin natural gas processors were forced to shut down their plants due to the shutdown of the Texas Gulf Coast NGL fractionators, we were able to produce our oil wells and vent or flare the associated natural gas. There is no certainty we will be able to vent or flare natural gas again due to potential changes in regulations. Furthermore, we may encounter problems in restarting production of previously shut-in wells.

Our commodity and interest rate derivative activities may limit our ability to profit from price gains, could result in cash losses and expose us to counterparty risk and as a result could reduce our cash available for distributions.

We have entered into, and we may in the future enter into, oil and natural gas derivative contracts intended to offset the effects of commodity 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.

In addition, we have entered into, and we may in the future enter into, interest rate swap contracts intended to offset the effects of interest rate volatility related to our outstanding indebtedness under our revolving credit facility. These instruments require us to make cash payments to the extent applicable floating interest rates are less than our contracted fixed rates, thereby limiting our ability to realize the benefit of declining interest rates.

There is always risk that counterparties in any commodity or interest rate derivative transaction cannot or will not perform under our derivative contracts. If a counterparty fails to perform and the derivative transaction is terminated, our cash flow and ability to pay distributions could be adversely impacted.

Further, 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 involuntary shut-ins or 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. Under our revolving credit facility, we are prohibited from entering into commodity derivative contracts covering all of our production, and we therefore retain the risk of a price decrease on our volumes not covered by commodity derivative contracts.

Due to regional fluctuations in the actual prices received for our natural gas production, the derivative contracts we enter into may not provide us with sufficient protection against price volatility since they are based on indexes related to different and remote regional markets.

We sell our natural gas into local markets, the majority of which is produced in West Texas, Southeast New Mexico, the Texas Panhandle, Central Oklahoma and Wyoming and shipped to the Midwest, West Coast and Texas Gulf Coast. These regions account for over 90% of our natural gas sales. Our existing natural gas swaps are based on Waha, ANR-Oklahoma and CIG-Rockies directly. While we are paid a local price indexed to or closely related to Waha, ANR-Oklahoma and CIG-Rockies, these indexes are heavily influenced by prices received in remote regional consumer markets less transportation costs and thus may not be effective in protecting us against local price volatility.

The substantial restrictions and financial covenants of our revolving credit facility, any negative redetermination of our borrowing base by our lenders and any potential disruptions of the financial markets could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We depend on our revolving credit facility for future capital needs. Our revolving credit facility, which matures on March 10, 2016, limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. As of February 22, 2012, our borrowing base was $550 million and we had $199.9 million available for borrowing.

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. We may not be able to comply with these restrictions and covenants in the future and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, such as any potential disruptions in the financial markets. 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.

Table of Contents

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 100% 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 100% 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 natural 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, such as a result of lower commodity prices or a deterioration in the condition of the financial markets, 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 Operation — Financing Activities.”

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.

Further, the present value of future net cash flows from our proved reserves may not be the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the un-weighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with Accounting Standards Codification (“ASC”) 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

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.

Table of Contents

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, 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 revolving 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 revolving 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 production and 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.

Many 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.

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;

Table of Contents

- 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, and cause a decline in the demand for yield-based equity investments such as our units.

Since all of the indebtedness outstanding under our revolving 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.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

We may not achieve the expected results of any acquisition we complete, and any adverse conditions or developments related to any such acquisition may have a negative impact on our operations and financial condition.

Further, even if we complete any acquisitions, which we would expect to increase pro forma distributable cash per unit, actual results may differ from our expectations and the impact of these acquisitions may actually result in a decrease in pro forma distributable cash per unit. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;

- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown environmental and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- the loss of key purchasers.

Our decision to acquire a property depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of newly acquired properties are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

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.

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, natural gas and interest rate derivative transactions 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 oil and 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 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.

Table of Contents

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.

Our sales of oil, natural gas, NGLs and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such 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.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”) provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges and cash collateral will have to be posted. The Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and the parties to those transactions. Since the Act mandates the Commodities Futures and Trading Commission (the “CFTC”), the federal regulators of banks and other financial institutions (the "Prudential Regulators") and the SEC to promulgate rules to define these terms, we do not know the definitions the regulators will actually adopt or how these definitions will apply to us. The CFTC and the other regulators are currently scheduled to adopt these rules and regulations in early 2012. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalent. Certain bona fide hedging transactions or positions would be exempt from these position limits.

Depending on the rules and definitions ultimately adopted by the regulators, we might in the future be required to post cash collateral for our commodities derivative transactions. Posting of cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. Although the CFTC and the Prudential Regulators have issued proposed rules under the

Act, we are at risk unless and until the CFTC and the Prudential Regulators adopt rules and definitions that confirm that companies such as us are not required to post cash collateral for our derivative hedging contracts. In addition, even if we are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Act's new requirements, and the costs of their compliance will likely be passed on to customers, including us, thus decreasing the benefits to us of hedging transactions and reducing the profitability of our cash flows.

Table of Contents

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress has considered legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale formations, as well as tight conventional formations including many of those that Legacy completes and produces. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. In addition, some states have adopted and others are considering legislation to restrict hydraulic fracturing. Texas and Wyoming have adopted legislation requiring the disclosure of hydraulic fracturing chemicals. Further, a Congressional Committee is investigating hydraulic fracturing practices legislation that requires the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition any additional level of regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the oil, natural gas and NGLs that we produce.

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other “greenhouse gases” present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth’s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. On January 2, 2011 regulations that require a reduction in emissions of greenhouse gases from motor vehicles became effective. The EPA has determined that such regulations trigger permit review for greenhouse gas emissions from certain stationary sources. EPA adopted a tiered approach to implementing the permitting of greenhouse gas emissions from stationary sources under the Clean Air Act permitting programs in May 2010. The so-called “tailoring rule” only requires the stationary sources with the largest emissions to undergo an assessment of greenhouse gas emissions under the "best available control technology" under the federal permitting programs. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published mandatory reporting rules for oil and gas systems requiring reporting starting in 2012 for emissions in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil, natural gas and NGL that we produce.

Legislation has been considered at the state and federal level. Any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil, NGL and natural gas that we produce.

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. The Founding Investors and their affiliates, including members of our management, own approximately 22% 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

Table of Contents

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.

Risks Related to Our Limited Partnership Structure

Our Founding Investors, including members of our management, own a 22% 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 22% limited partner interest in us and therefore have the ability to exercise a significant amount of control over the election of the entire board of directors of our general partner. 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.

Table of Contents

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

Table of Contents

- 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 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 constitutes "control" of our business.

Table of Contents

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 varying rates. 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 an entity-level state tax on the portion 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. Recently, members of Congress have considered substantive legislative changes to existing U.S. tax laws that would affect publicly traded partnerships. Although it does not appear that the legislation considered would have affected our tax treatment as a partnership, 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.

Table of Contents

Certain federal income tax deductions currently available with respect to oil and natural gas drilling and development may be eliminated as a result of future legislation.

President Obama's Proposed Fiscal Year 2013 Budget and other recently introduced legislation included proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and 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. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. 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.

23

Table of Contents

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 due to the potential recapture items, including depreciation, depletion and intangible drilling cost recapture. In addition, because the amount realized may include a unitholder’s share of our nonrecourse liabilities, if they sell their units, they may incur a tax liability in excess of the amount of cash they 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 and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, 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 consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

24

Table of Contents

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, Arkansas, Louisiana, Kansas, Montana and Utah. 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 which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Table of Contents

ITEM 2. PROPERTIES

As of December 31, 2011 we owned interests in producing oil and natural gas properties in 498 fields in the Permian Basin, Texas Panhandle, Wyoming, Oklahoma and several other states, operated 2,473 gross productive wells and owned non-operated interests in 3,483 gross productive wells. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2011. 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, 2011 Proved Reserves			Standardized Measure	
Field	MMBoe	R/P (a)	% Oil and NGLs	Amount (b)	% of Total
				($ in Millions)	
Spraberry/War San (c)	11.1	13.9	67 %	$ 217.5	19.1 %
Texas Panhandle	6.4	14.0	70	91.3	8.0
East Binger	3.3	11.5	84	71.3	6.2
Jordan	2.4	11.3	88	53.2	4.7
Langlie Mattix	1.5	17.5	88	40.2	3.5
Denton	2.2	12.6	82	39.0	3.4
Fourbear/Fourbear Frank's Fork	2.2	15.2	100	34.9	3.1
Farmer	1.8	23.6	66	30.8	2.7
Total — Top 8 fields	30.9	13.8	75 %	$ 578.2	50.7 %
All others	32.5	11.7	61	562.2	49.3
Total	63.4	12.6	68 %	$ 1,140.4	100.0 %

(a) Reserves as of December 31, 2011 divided by annualized fourth quarter production volumes.

(b) Texas margin taxes and the federal income taxes associated with a corporate subsidiary 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.

(c) As the Spraberry/War San field contains 11.1 MMBoe, or 17.5% of total proved reserves of 63.4 MMBoe, the following table presents the production, by product, for the Spraberry/War San field for the last three fiscal years:

	Year Ended December 31, 2011	2010	2009
	(In thousands, except daily production)		
Spraberry/War San Field Production:			
Oil (MBbls)	475	227	250
Natural gas liquids (Mgal)	346	44	63
Natural gas (MMcf)	1,514	922	861
Total (Mboe)	735	382	395
Average daily production (Boe per day)	2,014	1,047	1,082

Summary of Oil and Natural Gas Properties and Projects

Our most significant fields are the Spraberry/War San, Texas Panhandle, East Binger, Jordan, Langlie Mattix, Denton, Fourbear/Fourbear Frank's Fork and Farmer. As of December 31, 2011, these eight fields accounted for approximately 51% of our Standardized Measure and 49% of our total estimated proved reserves.

Spraberry/War San Field. The Spraberry/War San field is located in Andrews, Howard, Midland, Martin, Reagan and Upton Counties, Texas. This Spraberry/War San field summary includes wells in the War San field which produce from the same formations and in the same area as our Spraberry field wells. This field produces from

Table of Contents

Spraberry and Wolfcamp age formations from 5,000 to 11,000 feet. We operate 200 active wells (198 producing, 2 injecting) in this field with working interests ranging from 5.5% to 100% and net revenue interests ranging from 4.2% to 90.8%. We also own another 122 non-operated wells (120 producing, 2 injecting). As of December 31, 2011, our properties in the Spraberry/War San field contained 11.1 MMBoe (67% liquids) of net proved reserves with a standardized measure of $217.5 million. The average net daily production from this field was 2,183 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) for this field is 13.9 years based on the annualized fourth quarter production rate.

30 wells were drilled on Legacy Reserves' properties in the Spraberry/War San field in 2011. We have identified 65 more proved undeveloped projects, primarily 40-acre infill drilling locations, and 15 behind-pipe or proved developed non-producing re-completion projects in this field.

Texas Panhandle Fields. The Texas Panhandle fields are located in Carson, Gray, Hartley, Hutchinson, Moore, Potter, Sherman and Wheeler Counties, Texas. The fields are produced from multiple formations of Permian age which primarily include the shallow Granite Wash, Brown Dolomite, and Red Cave formations from 2,500 to 4,000 feet. Legacy operates 584 wells (542 producing, 42 injecting) in the Texas Panhandle fields with working interests ranging from 33.3% to 100% and net revenue interests ranging from 25% to 100.0%. We also own another 415 non-operated wells (403 producing, 12 injecting). As of December 31, 2011, our properties in the Texas Panhandle fields contained 6.4 MMBoe (70% liquids) of net proved reserves with a standardized measure of $91.3 million. The average net daily production from these fields was 1,250 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) for these fields is 14.0 years based on the annualized fourth quarter production rate.

East Binger Field. The East Binger field is located in Caddo County, Oklahoma. 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 81 wells (56 producing, 25 injecting) in the East Binger field, and Legacy owns a working interest of 55.67% and net revenue interest of 46.9% in the East Binger Unit. As of December 31, 2011, our properties in the East Binger field contained 3.3 MMBoe (84% liquids) of net proved reserves with a standardized measure of $71.3 million. The average net daily production from this field was 791 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) for the field is 11.5 years based on the annualized fourth quarter production rate.

Two infill wells were drilled in the East Binger Unit in 2011, and we have four more proved undeveloped projects identified in this field.

Jordan Field. The Jordan field is located in Ector and Crane Counties, Texas. The field produces under waterflood from the San Andres Formation at depths of 3,100 to 3,800 feet. We operate 70 wells (54 producing, 16 injecting) in the West Jordan Unit with a 53.1% working interest and a 39.8% net revenue interest. We also own a 35.9% non-operated working interest and a 29.7% net revenue interest in the Jordan University Unit which contains 180 wells (145 producing, 35 injecting). As of December 31, 2011, our properties in the Jordan field contained 2.4 MMBoe (88% liquids) of net proved reserves with a standardized measure of $53.2 million. The average net daily production from the field was 573 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) of the field is 11.3 years based on the annualized fourth quarter production rate.

The Jordan University Unit was drilled in the 1930s through the 1960s on 20-acre spacing and waterflooding commenced in 1966. There have been over 100 infill wells drilled in the unit including two 10-acre infill and eight 5-acre infill wells drilled in 2011. We have 20 more proved undeveloped drilling locations in the unit.

The West Jordan Unit was drilled in the 1930s through the 1960s on 20-acre spacing and waterflooding began in 1970. There have been 68 10-acre infill wells drilled in the unit including three infill wells drilled in 2011. We have six proved developed 10-acre drilling locations and 10 more proved developed non-producing projects in the unit.

Langlie Mattix Field. The Langlie Mattix field is 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 98 wells (72 producing, 26 injecting) in the Langlie Mattix Penrose Sand Unit, a subdivision of the Langlie Mattix Field,

Table of Contents

with a 59.0% average working interest and a 50.7% average net revenue interest. We also operate 45 producing wells in the Skelly Penrose A Unit with a 100% working interest and a 86.8% net revenue interest, as well as five other properties with eight active producing wells with an average net working interest of 95.9% and 80.8% net revenue interests. As of December 31, 2011, our properties in the Langlie Mattix field contained 1.5 MMBoe (88% liquids) of net proved reserves with a standardized measure of $40.2 million. The average net daily production from this field was 237 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) for the field is 17.5 years based on the annualized fourth quarter production rate.

The Langlie Mattix Penrose Sand Unit was drilled in the late 1930s and early 1940s on 40-acre spacing. Waterflooding commenced in 1958. There have been a total of 26 20-acre infill wells drilled on the Unit in four different drilling programs from 1983 to 2007. All four 20-acre infill drilling programs were successful. We have 23 more proved undeveloped locations and an additional 41 unproved 20-acre locations.

Denton Field. The Denton field is 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 21 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 nine wells (seven producing, two injecting) with a 15% average non-operated working interest and a 13.1% average net revenue interest. As of December 31, 2011, our properties in the Denton field contained 2.2 MMBoe (82% liquids) of net proved reserves with a standardized measure of $39.0 million. The average net daily production from this field was 474 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) for the field is 12.6 years based on the annualized fourth quarter production rate.

Fourbear/Fourbear Frank’s Fork Fields. The Fourbear and Fourbear Frank’s Fork fields are located in Park County in the Big Horn Basin of Wyoming. These fields produce from multiple formations which primarily include the Pennsylvanian age Phosphoria and Tensleep formations from 3,000 to 4,000 feet. Legacy operates 66 wells (41 producing, 25 injecting) in these fields with working interests ranging from 83.1% to 100% and net revenue interests ranging from 72.2% to 89.1%. As of December 31, 2011, our properties in the Fourbear and Fourbear Frank’s Fork fields contained 2.2 MMBoe (100% liquids) of net proved reserves with a standardized measure of $34.9 million. The average net daily production from these fields was 405 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) for these fields is 15.2 years based on the annualized fourth quarter production rate.

We have identified three proved undeveloped projects and seven behind-pipe or proved developed non-producing projects in these fields. We also have 10 additional unproved drilling locations in these fields.

Farmer Field. The Farmer field is 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 154 wells (146 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, 2011, our properties in the Farmer field contained 1.8 MMBoe (66% liquids) of net proved reserves with a standardized measure of $30.8 million. The average net daily production from this field was 212 Boe/d for the fourth quarter of 2011. The estimated reserve life (R/P) for the field is 23.6 years based on the annualized fourth quarter production rate.

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 have identified 29 10-acre proved undeveloped locations in this field and an additional 84 unproved 10-acre locations.

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. ("LaRoche"). 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.

Table of Contents

The following information represents estimates of our proved reserves as of December 31, 2011, 2010 and 2009. These reserve estimates have been prepared in compliance with the Securities and Exchange Commission rules and accounting standards using current costs and the average annual prices based on the un-weighted arithmetic average of the first-day-of-the-month price for each month in the years ended December 31, 2011, 2010 and 2009. The pricing that was used for estimates of our reserves as of December 31, 2011 was based on an un-weighted 12-month average West Texas Intermediate posted price of $92.71 per Bbl for oil and a NYMEX natural gas price of $4.12 per MMBtu. See the table below.

	As of December 31,		
	2011	2010	2009
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	38.2	34.1	21.7
Natural Gas Liquids (MMBbls)	4.8	4.9	5.0
Natural Gas (Bcf)	122.6	82.7	62.4
Total (MMBoe)	63.4	52.8	37.1
Proved developed reserves (MMBoe)	55.4	46.4	31.6
Proved undeveloped reserves (MMBoe)	8.0	6.4	5.5
Proved developed reserves as a percentage of total proved reserves	87 %	88 %	85 %
Standardized measure (in millions)(a)	$1,140.4	$774.8	$360.2
Oil and Natural Gas Prices(b)			
Oil - NYMEX WTI per Bbl	$92.71	$75.96	$57.65
Natural gas - NYMEX Henry Hub per MMBtu	$4.12	$4.38	$3.87

(a) 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 current costs and the average annual prices based on the un-weighted arithmetic average of the first-day-of-the-month price) 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%. For the purpose of calculating the standardized measure, the costs and prices are unescalated. Because we are a limited partnership that allocates our taxable income to our unitholders, no provision for federal or state income taxes has 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 Operation — Cash Flow from Operations."

(b) Oil and natural gas prices as of each date are the average annual prices based on the un-weighted arithmetic average of the first-day-of-the-month price for each month, with these representative prices adjusted by property to arrive at the appropriate net sales price, which is held constant over the economic life of the property.

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 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 for re-completion.

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

Table of Contents

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 to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither LaRoche nor any of its employees have 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 2011, 2010 and 2009, we paid LaRoche approximately $337,372, $151,176 and $141,666, respectively, for such reserve and economic evaluations.

Internal Control over Reserve Estimations

Legacy's proved reserves are estimated at the well or unit level and compiled for reporting purposes by Legacy's reservoir engineering staff, none of whom are members of Legacy's operating teams nor are they managed by members of Legacy's operating teams. Legacy maintains internal evaluations of its reserves in a secure engineering database. Legacy's reservoir engineering staff meets with LaRoche periodically throughout the year to discuss assumptions and methods used in the reserve estimation process. Legacy provides LaRoche information on all properties acquired during the year for addition to Legacy’s reserve report. LaRoche updates production data from public sources and then modifies production forecasts for all properties as necessary. Legacy provides to LaRoche lease operating statement data at the property level from Legacy’s accounting system for estimation of each property’s operating expenses, price differentials, gas shrinkage and NGL yield. Legacy's reserve engineering staff provides all changes to Legacy’s ownership interests in the properties to LaRoche for input into the reserve report. Legacy provides information on all capital projects completed during the year as well as changes in the expected timing of future capital projects. Legacy provides updated capital project cost estimates and abandonment cost and salvage value estimates. Legacy's internal engineering staff coordinates with Legacy's accounting and other departments and works closely with LaRoche to ensure the integrity, accuracy and timeliness of data that is furnished to LaRoche for its reserve estimation process. All of the reserve information in Legacy's secure reserve engineering data base is provided to LaRoche. After evaluating and inputting all information provided by Legacy, LaRoche, as independent third-party petroleum engineers, provides Legacy with a preliminary reserve report which Legacy's engineering staff and its President and Chief Financial Officer review for accuracy and completeness with an emphasis on ownership interest, capital spending and timing, expense estimates and production curves. After considering comments provided by Legacy, LaRoche completes and publishes the final reserve report. Legacy's engineering staff, in coordination with Legacy's accounting department and President and Chief Financial Officer, ensure that the information derived from LaRoche's reports is properly disclosed in our filings.

Legacy’s Acquisition and Planning Manager is the reservoir engineer primarily responsible for overseeing the preparation of reserve estimates by the third-party engineering firm, LaRoche. He has held a wide variety of technical and supervisory positions during a 34-year career with four publicly traded oil and natural gas producing companies, including Legacy. He has over 24 years of SEC reserve report preparation experience in addition to continuing education courses on reserve estimation and reporting, including one in 2009 covering the effect of the SEC’s Final Rule, Modernization of Oil and Gas Reporting. For the professional qualifications of the primary person responsible for the third party reserve evaluation, please see the last paragraph of Exhibit 99.1 - Summary Reserve Report from LaRoche Petroleum Consultants, Ltd.

Table of Contents

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 years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010(a)	2009
Production:			
Oil (MBbls)	2,951	2,334	1,800
Natural gas liquids (MGal)	14,559	12,890	15,118
Gas (MMcf)	8,842	5,204	5,055
Total (MBoe)	4,771	3,508	3,002
Average daily production (Boe per day)	13,071	9,611	8,225
Average sales price per unit (excluding derivatives):			
Oil (per Bbl)	$89.62	$74.02	$57.40
NGL (per Gal)	$1.30	$1.06	$0.76
Gas (per Mcf)	$6.05	$5.76	$4.43
Combined (per Boe)	$70.61	$61.68	$45.73
Average sales price per unit (including realized derivative gains/losses):			
Oil (per Bbl)	$85.78	$77.99	$78.47
NGL (per Gal)	$1.30	$1.06	$0.81
Gas (per Mcf)	$7.41	$7.86	$7.17
Combined (per Boe)	$70.74	$67.42	$63.21
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$18.37	$17.97	$14.76
Ad valorem taxes	$1.95	$1.77	$1.50
Production and other taxes	$4.26	$3.62	$2.71
General and administrative	$4.84	$5.49	$5.16
Depletion, depreciation and amortization	$18.48	$17.93	$19.57

(a) Reflects the production and operating results of the Wyoming and COG acquisition properties from the closing dates of such acquisitions on February 17, 2010 and December 22, 2010, respectively, through December 31, 2010.

Productive Wells

The following table sets forth information at December 31, 2011 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	2,141	1,743	332	285
Non-operated	2,651	270	832	100
Total	4,792	2,013	1,164	385

31

Table of Contents

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2011 relating to our leasehold acreage.

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross(c)	Net(d)	Gross(c)	Net(d)
Total	657,491	230,323	31,919	13,540

(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 with respect to wells completed by Legacy during the years ended December 31, 2011, 2010 and 2009. The drilling activities associated with the properties acquired in the Wyoming acquisition (February 17, 2010) and the COG acquisition (December 22, 2010) are included 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 numbers 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,		
	2011	2010	2009
Gross:			
Development			
Productive	92	42	22
Dry	—	—	—
Total	92	42	22
Exploratory			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—
Net:			
Development			
Productive	32.3	18.1	5.7

Dry	—	—	—
Total	32.3	18.1	5.7
Exploratory			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—

Table of Contents

Summary of Development Projects

We are currently pursuing an active development strategy. We estimate that our capital expenditures for the year ending December 31, 2012 will be approximately $62 million for development drilling, re-completions and fracture stimulation and other development related projects to implement this strategy. This capital budget includes, but is not limited to, the drilling of 52 gross (28.0 net) development wells and execution of 24 gross (18.1 net) re-completions and fracture simulations projects, all of which are included in our SEC reserve report. All of these development projects are located in the Permian Basin, Texas Panhandle, Wyoming and the East Binger field in Oklahoma. We will consider adjustments to this capital program based on our assessment of additional development opportunities that are identified during the year and the cash available to invest in our development projects.

Operations

General

We operate approximately 73% of our net daily production of oil and natural gas. We design and manage the development, re-completion or workover 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 and a cable tool rig used for shallow well work in the Texas Panhandle fields. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ drilling, production, and reservoir engineers, contract 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 also employ field operating personnel including production superintendents, production foremen, production technicians and lease operators. 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 an 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 was initially anticipated 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, NGL 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. The majority of our derivative contracts are in the form of fixed price swaps for NYMEX WTI oil, West Texas Waha natural gas, ANR-Oklahoma natural gas and Rocky Mountain CIG natural gas. Additionally, we have sold two call options related to an existing WTI oil swap. These swap related options (“swaptions”) allow the counterparty to extend the contract covering calendar year 2011 to either 2012, 2013 or both. The counterparty exercised the option covering calendar year 2012 on December 30, 2011 and must exercise or decline the option

Table of Contents

covering calendar year 2013 on December 31, 2012. We have also entered into a NYMEX WTI oil collar that combines a long put option or "floor" with a short call option or "ceiling", as well as multiple NYMEX WTI oil derivative three-way collar contracts. Each three-way contract combines a short call, a long put and a short put. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk. Like a collar, we receive the short call price (net) if the market price is above the short call price, and we receive the market price if the market price is in between the short call and long put prices. Unlike a collar, however, if the market price is below the price of the long put, we receive the long put price only if the market price is still above the short put price. If the market price has fallen below the short put price, we receive the NYMEX WTI market price plus the spread between the short put and the long put prices. We also 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. All of our derivative counterparties are members of our bank group. For a more detailed discussion of our derivative activities, please read "Business – Oil and Natural Gas Derivative Activities," "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, except as discussed in Note 6 in the Notes to the Consolidated Financial Statements, 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. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

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 February 22, 2012, there were 47,920,179 units outstanding, held by approximately 86 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.

	Price Ranges		Cash Distribution	Cash Distribution	
2011	High	Low	per Unit	to General Partner	
First Quarter	$32.24	$27.84	$0.53	$9,705	
Second Quarter	$33.71	$27.01	$0.54	$9,888	
Third Quarter	$30.85	$22.00	$0.545	$9,979	
Fourth Quarter	$30.85	$23.84	$0.55	$10,071	(a)
	Price Ranges		Cash Distribution	Cash Distribution	
2010	High	Low	per Unit	to General Partner	
First Quarter	$23.22	$17.04	$0.52	$9,522	
Second Quarter	$24.75	$17.86	$0.52	$9,522	
Third Quarter	$26.09	$21.25	$0.52	$9,522	
Fourth Quarter	$29.19	$24.66	$0.525	$9,613	

(a) This distribution was paid to our general partner concurrent with our distribution to unitholders on February 14, 2012.

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 $0.55 per unit.

Recent Sales of Unregistered Securities

On November 14, 2011 we issued 278,396 units as partial consideration to a private seller for oil and natural gas producing properties located in Lea, Eddy and Chaves Counties, New Mexico. The issuance of these units were exempt from registration under Section 4(2) of the Securities Act because the issuance did not involve a public offering.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

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. The operating results of the properties acquired have been included from their respective acquisition dates as discussed below.

	Years Ended December 31,				
	2011	2010(a)	2009	2008(b)	2007(c)
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$264,473	$172,754	$103,319	$157,973	$83,301
Natural gas liquids sales	18,888	13,670	11,565	15,862	7,502
Natural gas sales	53,524	29,965	22,395	41,589	21,433
Total revenues	336,885	216,389	137,279	215,424	112,236
Expenses:					
Oil and natural gas production	96,914	69,228	48,814	52,004	27,129
Production and other taxes	20,329	12,683	8,145	12,712	7,889
General and administrative	23,084	19,265	15,502	11,396	8,392
Depletion, depreciation, amortization and accretion	88,178	62,894	58,763	63,324	28,415
Impairment of long-lived assets	24,510	13,412	9,207	76,942	3,204
(Gain) loss on disposal of assets	(625)	592	378	602	527
Total expenses	252,390	178,074	140,809	216,980	75,556
Operating income (loss)	84,495	38,315	(3,530)	(1,556)	36,680
Other income (expense):					
Interest income	15	10	9	93	321
Interest expense	(18,566)	(25,766)	(13,222)	(21,153)	(7,118)
Equity in income of partnerships	138	97	31	108	77
Realized and unrealized net gains (losses) on commodity derivatives	6,857	(1,400)	(75,554)	176,943	(85,156)
Other	152	90	(11)	116	(129)
Income (loss) before income taxes	73,091	11,346	(92,277)	154,551	(55,325)
Income taxes	(1,030)	(537)	(554)	(48)	(337)
Net income (loss) from continuing operations	$72,061	$10,809	$(92,831)	$154,503	$(55,662)
Income (loss) per unit					
Basic and diluted	$1.63	$0.27	$(2.89)	$5.05	$(2.13)
Distributions paid per unit	$2.14	$2.08	$2.08	$1.98	$1.67
Cash Flow Data:					
Net cash provided by operating activities	$184,237	$101,371	$37,476	$140,985	$57,147
Net cash provided by (used in) investing activities	$(206,816)	$(285,246)	$23,294	$(258,035)	$(196,505)
Net cash provided by (used in) financing activities	$22,252	$183,136	$(59,053)	$109,946	$147,900
Capital expenditures	$207,565	$311,277	$22,734	$217,980	$196,702

Table of Contents

	Historical As of December 31,				
	2011	2010(a)	2009	2008(b)	2007(c)
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$3,151	$3,478	$4,217	$2,500	$9,604
Other current assets	56,634	47,120	45,394	78,437	23,954
Oil and natural gas properties, net of accumulated depletion, depreciation and amortization	959,329	843,836	575,425	613,032	440,180
Other assets	24,374	14,992	28,457	89,103	7,840
Total assets	$1,043,488	$909,426	$653,493	$783,072	$481,578
Current liabilities	$97,450	$72,955	$54,226	$56,032	$43,457
Long term debt	337,000	325,000	237,000	282,000	110,000
Other long-term liabilities	120,703	119,732	83,607	64,407	72,391
Unitholders' equity	488,335	391,739	278,660	380,633	255,730
Total liabilities and unitholders' equity	$1,043,488	$909,426	$653,493	$783,072	$481,578

(a) Reflects Legacy's purchase of the oil and natural gas properties acquired in the Wyoming and COG Acquisitions as of the date of their respective acquisitions. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2010 and thereafter.

(b) Reflects Legacy's purchase of the oil and natural gas properties acquired in the COP III and Pantwist Acquisitions as of the date of their respective acquisitions. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2008 and thereafter.

(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 respective acquisitions. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2007 and thereafter.

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

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 this 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 oil and 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 Statement Regarding Forward-Looking Information," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, actual results may differ materially from those anticipated or implied in the forward-looking statements.

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.

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. The operating results of the properties acquired in the Wyoming Acquisition have been included from February 17, 2010 and the operating results of the acquisition of oil and natural gas properties from a subsidiary of Concho Resources, Inc (the “COG Acquisition”) have been included from December 22, 2010. During 2011, we consummated $142.2 million of acquisitions in 28 individually immaterial transactions. The operating results of these acquisitions have been included from their respective acquisition dates.

Trends Affecting Our Business and Operations

Acquisitions have been financed with a combination of proceeds from bank borrowings, 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.

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 acquiring more reserves than we produce, drilling to find additional reserves, utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary (CO_2 and nitrogen) recovery methods to re-pressure the reservoir and recover additional oil, recompleting or adding pay in existing wellbores and improving artificial lift. 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 entered into oil, NGL and natural gas derivatives designed to mitigate the effects of price fluctuations covering a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil, NGL 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 on any redetermination to our borrowing base under our revolving 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.

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 or re-completed.

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 workover 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. We do not consider royalties paid to mineral owners an expense as we deduct hydrocarbon volumes owned by mineral owners from reported hydrocarbon sales volumes.

Table of Contents

Operating Data

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

	Year Ended December 31,		
	2011	2010(a)	2009
	(In thousands, except per unit data and production)		
Revenues			
Oil sales	$264,473	$172,754	$103,319
Natural gas liquid sales	18,888	13,670	11,565
Natural gas sales	53,524	29,965	22,395
Total revenues	$336,885	$216,389	$137,279
Expenses:			
Oil and natural gas production	$87,626	$63,024	$44,308
Ad valorem taxes	$9,288	$6,204	$4,506
Total	$96,914	$69,228	$48,814
Production and other taxes	$20,329	$12,683	$8,145
General and administrative	$23,084	$19,265	$15,502
Depletion, depreciation, amortization and accretion	$88,178	$62,894	$58,763
Realized commodity derivative contract settlements:			
Realized gain (loss) on oil swaps	$(11,335)	$9,263	$37,919
Realized gain (loss) on natural gas liquid swaps	$—	$(39)	$733
Realized gain on natural gas swaps	$11,972	$10,913	$13,825
Production:			
Oil (MBbls)	2,951	2,334	1,800
Natural gas liquids (MGal)	14,559	12,890	15,118
Natural gas (MMcf)	8,842	5,204	5,055
Total (MBoe)	4,771	3,508	3,002
Average daily production (Boe/d)	13,071	9,611	8,225
Average sales price per unit (excluding derivatives):			
Oil price (per Bbl)	$89.62	$74.02	$57.40
Natural gas liquid price (per Gal)	$1.30	$1.06	$0.76
Natural gas price (per Mcf)	$6.05	$5.76	$4.43
Combined (per Boe)	$70.61	$61.68	$45.73
Average sales price per unit (including realized derivative gains/losses):			
Oil price (per Bbl)	$85.78	$77.99	$78.47
Natural gas liquid price (per Gal)	$1.30	$1.06	$0.81
Natural gas price (per Mcf)	$7.41	$7.86	$7.17
Combined (per Boe)	$70.74	$67.42	$63.21
NYMEX oil index prices per Bbl:			
Beginning of Period	$91.38	$79.36	$44.60
End of Period	$98.83	$91.38	$79.36
NYMEX gas index prices per Mcf:			
Beginning of Period	$4.41	$5.57	$5.62
End of Period	$2.99	$4.41	$5.57
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$18.37	$17.97	$14.76

Ad valorem taxes	$1.95	$1.77	$1.50
Production and other taxes	$4.26	$3.62	$2.71
General and administrative	$4.84	$5.49	$5.16
Depletion, depreciation, amortization and accretion	$18.48	$17.93	$19.57

(a) Reflects the production and operating results of the oil and natural gas properties acquired in the Wyoming and COG Acquisitions from the closing dates of such acquisitions through December 31, 2010 and thereafter.

Table of Contents

Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Legacy's revenues from the sale of oil were $264.5 million and $172.8 million for the years ended December 31, 2011 and 2010, respectively. Legacy's revenues from the sale of NGLs were $18.9 million and $13.7 million for the years ended December 31, 2011 and 2010, respectively. Legacy's revenues from the sale of natural gas were $53.5 million and $30.0 million for the years ended December 31, 2011 and 2010, respectively. The $91.7 million increase in oil revenue reflects an increase in oil production of 617 MBbls (26%) due primarily to acquisitions of producing properties, a full year of production from the Wyoming and COG Acquisitions and our development activities that were primarily focused on oil-weighted projects in the Permian Basin. In addition, we realized a $15.60 per Bbl (21%) increase in realized oil sales price from $74.02 for the year ended December 31, 2010 to $89.62 for the year ended December 31, 2011. The $5.2 million increase in NGL revenues reflects an increase in realized NGL price of $0.24 per Gal (23%) from $1.06 per Gal for the year ended December 31, 2010 to $1.30 per Gal for the year ended December 31, 2011, as well as an increase in NGL production of 1,669 MGal (13%) due primarily to significantly lower plant and gathering system downtime during 2011 from one of our NGL purchasers in the Texas Panhandle than was experienced during 2010. The $23.6 million increase in natural gas revenues reflects an increase in natural gas production of approximately 3,638 MMcf (70%) due primarily to acquisitions of producing properties, a full year of production from the COG Acquistion and our development activities. The Wolfberry play, which is our primary focus of development activity in the Permian Basin, produces mostly oil but also a significant amount of NGL-rich casinghead natural gas. In addition, we realized a $0.29 per Mcf (5%) increase in natural gas sales price from $5.76 per Mcf for the year ended December 31, 2010 to $6.05 per Mcf for the year ended December 31, 2011, which reflects the increased NGL prices embedded into our revenue from our sales of wet natural gas, primarily in the Permian Basin, which more than offset the decline in NYMEX Henry Hub natural gas prices. Most of our purchasers of natural gas in the Permian Basin compensate us for the NGL content in our wet natural gas volumes, but do not separately account for such volumes. As such, we do not report any of these natural gas volumes as NGLs. Accordingly, our realized natural gas prices in the Permian Basin and for Legacy as a whole are substantially higher than NYMEX Henry Hub natural gas prices due to the NGL content in our wet natural gas sales.

For the year ended December 31, 2011, Legacy recorded $6.9 million of net gains on oil and natural gas derivatives comprised of realized gains of $0.6 million from net cash settlements of oil, NGL and natural gas derivative contracts and net unrealized gains of $6.2 million. Legacy had unrealized net losses of $0.7 million from its oil derivatives as an increase in NYMEX oil futures prices from December 31, 2010 to December 31, 2011 more than offset the increase in the average fixed price of Legacy's oil derivatives contracts, resulting in a larger net oil derivative liability. Legacy had unrealized net gains of $6.9 million from its natural gas derivatives as a decrease in NYMEX natural gas futures prices from December 31, 2010 to December 31, 2011 was only partially offset by the decrease in the average fixed price of Legacy's natural gas derivative contracts, resulting in a larger net natural gas derivative asset. For the year ended December 31, 2010, Legacy recorded $18.3 million of net losses on oil swaps comprised of a realized gain of $9.3 million from net cash settlements of oil swap contracts and a net unrealized loss of $27.5 million. For the year ended December 31, 2010, Legacy recorded $16.9 million of net gains on natural gas swaps comprised of a realized gain of $10.9 million from net cash settlements of natural gas swap contracts and a net unrealized gain of $5.9 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 ad valorem taxes, increased to $87.6 million ($18.37 per Boe) for the year ended December 31, 2011 from $63.0 million ($17.97 per Boe) for the year ended December 31, 2010. Production expenses increased primarily because of (i) $8.2 million of increased production expenses related to the COG Acquisition as this acquisition was closed on December 22, 2010 and thus only had 8 days of expense in 2010, (ii) $2.7 million related to increases in workover activity, (iii) production expenses from other acquisitions and

(iv) an industry wide increase in cost of services and certain operating costs that are related to the higher oil prices and increased industry activity during the year ended December 31, 2011. Legacy's ad valorem tax expense increased to $9.3 million ($1.95 per Boe) for the year ended December 31, 2011 from $6.2 million ($1.77 per Boe) for the year ended December 31, 2010 primarily due to the properties acquired in the COG Acquisition and increased oil and NGL prices, which increases the property valuations upon which these taxes are based.

Legacy’s production and other taxes were $20.3 million and $12.7 million for the years ended December 31, 2011 and 2010, respectively. Production and other taxes increased primarily because of higher realized commodity prices and production volumes in 2011 as production and other taxes are assessed as a percentage of revenue and that percentage remained relatively unchanged between 2011 and 2010.

Legacy’s general and administrative expenses were $23.1 million and $19.3 million for the years ended December 31, 2011 and 2010, respectively. General and administrative expenses increased approximately $3.8 million between periods primarily due to (i) increased salaries and benefits due to the hiring of additional personnel commensurate with the growth of our asset base, (ii) a $1.9 million charge, recognized in the fourth quarter of 2011, related to the termination of a purchase and sale agreement and related due diligence costs and (iii) a $0.8 million increase in insurance expenses encompassing corporate, director and officer and employee insurance plans. These increases were partially offset by lower unit-based compensation expense of $1.5 million as increases in Legacy's unit price during 2010 resulted in higher LTIP expense during 2010.

Legacy’s depletion, depreciation, amortization and accretion expense, or DD&A, was $88.2 million and $62.9 million for the years ended December 31, 2011 and 2010, respectively, reflecting primarily the increase in production and cost basis related to our recent acquisitions and development activity partially offset by increased reserves related to our development activities, acquisitions and higher average oil prices during the year ended December 31, 2011 compared to the year ended December 31, 2010. As a point of reference, our depletion rate per Boe for the year ended December 31, 2011 was $18.48 compared to $17.93 for the year ended December 31, 2010.

Impairment expense was $24.5 million and $13.4 million for the years ended December 31, 2011 and 2010, respectively. In 2011, Legacy recognized impairment expense in 70 separate producing fields, due primarily to the decrease in natural gas prices during the year ended December 31, 2011, combined with higher lifting costs, which decreased the expected future cash flows below the carrying value of the assets. In 2010, Legacy recognized impairment expense in 67 separate producing fields due primarily to (i) the decrease in natural gas prices during the year ended December 31, 2010 combined with higher lifting costs, which decreased the expected future cash flows below the carrying value of the assets, (ii) the write-off of multiple locations of proved undeveloped reserves (“PUDs”) in one field due to the performance of offset locations that no longer supported the economic viability of the PUDs and (iii) the performance decline of two wells in two separate fields.

Interest expense was $18.6 million and $25.8 million for the years ended December 31, 2011 and 2010, respectively. The reduction in interest expense is primarily due to an unrealized mark-to-market benefit related to our interest rate swaps of $1.9 million in 2011 compared to an unrealized $7.3 million mark-to-market expense in 2010. The addition and cashless restructuring of interest rate swaps at favorable rates during 2011, combined with a slight increase in shorter term LIBOR rates in the fourth quarter of 2011, resulted in a reduced interest rate swap liability and thus a mark-to-market gain which reduced Legacy's interest expense. This decrease was partially offset by an increase in interest expense due to higher average debt balance during 2011 compared to 2010.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Legacy’s revenues from the sale of oil were $172.8 million and $103.3 million for the years ended December 31, 2010 and 2009, respectively. Legacy’s revenues from the sale of NGLs were $13.7 million and $11.6 million for the years ended December 31, 2010 and 2009, respectively. Legacy’s revenues from the sale of natural gas were $30.0 million and $22.4 million for the years ended December 31, 2010 and 2009, respectively. The $69.5 million increase in oil revenue reflects an increase in oil production of 534 MBbls (30%) due primarily to acquisitions of producing properties, including the Wyoming and COG Acquisitions, and our development activities. In addition, we realized a $16.62 per Bbl (29%) increase in realized sales price from $57.40 for the year ended December 31, 2009, to $74.02

for the year ended December 31, 2010. The $2.1 million increase in NGL revenues reflects an increase in realized NGL price of $0.30 per Gal (39%) from $0.76 per Gal for the year ended December 31, 2009, to $1.06 per Gal for the year ended December 31, 2010. However, this increase in NGL prices was offset by a decrease in NGL production of 2,228 MMGal (15%) due primarily to significant plant and gathering system downtime from one of our NGL purchasers in the Texas Panhandle. The $7.6 million increase in natural gas revenues reflects an increase in natural gas production of approximately 149 MMcf (3%) due primarily to acquisitions of producing properties, including the Wyoming and COG Acquisitions, and our development activities. In addition, we realized a $1.33 per Mcf (30%) increase in natural gas sales price from $4.43 per Mcf for the year ended December 31, 2009, to $5.76 per Mcf for the year ended December 31, 2010.

Table of Contents

For the year ended December 31, 2010, Legacy recorded $1.4 million of net losses on oil and natural gas derivatives comprised of realized gains of $20.1 million from net cash settlements of oil, NGL and natural gas derivative contracts and net unrealized losses of $21.5 million. Legacy had unrealized net losses from its oil swaps due to the increase in NYMEX oil prices during the year ended December 31, 2010 from $79.36 per Bbl at December 31, 2009 to $91.38 at December 31, 2010, a price which is above the fixed price of Legacy's oil derivative contracts. Legacy had unrealized net gains from its natural gas swaps due to the decrease in NYMEX natural gas prices from $5.57 per MMBtu at December 31, 2009 to $4.41 per MMBtu at December 31, 2010, a price which is below the fixed price of Legacy's natural gas derivative contracts. For the year ended December 31, 2009, Legacy recorded $85.6 million of net losses on oil derivatives comprised of a realized gain of $37.9 million from net cash settlements of oil derivative contracts and a net unrealized loss of $123.5 million. For the year ended December 31, 2009, Legacy recorded $0.6 million of net losses on NGL swaps comprised of a realized gain of $0.7 million from net cash settlements of NGL swap contracts and a net unrealized loss of $1.3 million. For the year ended December 31, 2009, Legacy recorded $10.6 million of net gains on natural gas derivatives comprised of a realized gain of $13.8 million from net cash settlements of natural gas derivative contracts and a net unrealized loss of $3.2 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 ad valorem taxes, increased to $63.0 million ($17.97 per Boe) for the year ended December 31, 2010 from $44.3 million ($14.76 per Boe) for the year ended December 31, 2009. Production expenses increased primarily because of (i) $8.8 million of production expenses related to the Wyoming and COG Acquisitions, (ii) $1.1 million related to increases in workover activity, (iii) $0.9 million in one-time expenses related to regulatory compliance and casualty losses, (iv) production expenses from other acquisitions and (v) an industry wide increase in cost of services and certain operating costs that are directly related to the higher commodity prices experienced during the year ended December 31, 2010, including the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil, and the higher level of industry activity resulting from higher oil prices. Legacy's ad valorem tax expense increased to $6.2 million ($1.77 per Boe) for the year ended December 31, 2010 from $4.5 million ($1.50 per Boe) for the year ended December 31, 2009 primarily due to the properties acquired in the Wyoming Acquisition.

Legacy's production and other taxes were $12.7 million and $8.1 million for the years ended December 31, 2010 and 2009, respectively. Production and other taxes increased primarily because of higher realized commodity prices in the 2010 period as production taxes are assessed as a percentage of revenue.

Legacy's general and administrative expenses were $19.3 million and $15.5 million for the years ended December 31, 2010 and 2009, respectively. General and administrative expenses increased approximately $3.8 million between periods primarily due to (i) a $2.4 million increase in non-cash compensation expense related to the LTIP for the year ended December 31, 2010 due to increases in Legacy's unit price, (ii) $0.7 million of acquisition costs and (iii) $0.3 million of one-time expenses related to Legacy's accounting system conversion, the ultimate implementation of which occurred in January 2011.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $62.9 million and $58.8 million for the years ended December 31, 2010 and 2009, respectively, reflecting primarily the increase in production and cost basis related to the Wyoming and COG acquisitions partially offset by increased reserves related to our development activities, acquisitions and higher oil prices during the year ended December 31, 2010 compared to the year ended December 31, 2009. As a point of reference, our depletion rate per Boe for the year ended December 31, 2010 was $17.93 compared to $19.57 for the year ended December 31, 2009.

Impairment expense was $13.4 million and $9.2 million for the years ended December 31, 2010 and 2009, respectively. In 2010 Legacy recognized impairment expense in 67 separate producing fields, due primarily to (i) the decrease in natural gas prices during the year ended December 31, 2010 combined with higher lifting costs, which decreased the expected future cash flows below the carrying value of the assets, (ii) the write-off of multiple locations of proved undeveloped reserves ("PUDs") in one field due to the performance of offset locations that no longer supported the economic viability of the PUDs and (iii) the performance decline of two wells in two separate fields. In 2009 Legacy recognized impairment expense in 20 separate producing fields due primarily to declines in realized natural gas prices during the year ended December 31, 2009, as well as an unsuccessful re-completion activity in the case of one field, both of which resulted in reduced future expected cash flows.

Table of Contents

Interest expense was $25.8 million and $13.2 million for the years ended December 31, 2010 and 2009, respectively, reflecting a larger average debt balance during 2010 compared to 2009 as well as a mark-to-market adjustment related to our interest rate swaps resulting in a $7.3 million increase in interest expense in 2010 compared to a $3.8 million reduction of interest expense from the mark-to-market in 2009. As our interest rate swaps are fixed rates, the declining LIBOR interest rates in fiscal year 2010 resulted in increases in interest expense as the negative margin between our fixed rate swap and market rates increased. In addition, Legacy experienced an increase in interest rate swap settlements of $1.8 million in 2010 compared to 2009. These increases were partially offset by a decrease in interest expense due to lower average interest rates during 2010 compared to 2009.

Non-GAAP Financial Measures

For the year ended December 31, 2011, Adjusted EBITDA increased 44% to $202.0 million from $140.4 million for the year ended December 31, 2010. This increase is due primarily to Legacy's $120.5 million increase in revenues for the year ended December 31, 2011 compared to the year ended December 31, 2010, partially offset by higher expenses, including increases in production expenses, production taxes and general and administrative expenses that totaled $39.2 million, as well as a decrease in cash receipts on commodity derivatives of $19.5 million from the year ended December 31, 2010 to the year ended December 31, 2011. Distributable Cash Flow increased 22% to $108.5 million from $89.0 million for the year ended December 31, 2011 and 2010, respectively, due primarily to higher Adjusted EBITDA offset by higher development capital expenditures of $38.7 million and cash interest expense of $3.0 million in 2011 compared to 2010.

Legacy's management uses Adjusted EBITDA and Distributable Cash Flow as tools to provide additional information and metrics relative to the performance of Legacy's business, such as the cash distributions Legacy expects to pay to its unitholders. Legacy's management believes that both Adjusted EBITDA and Distributable Cash Flow are useful to investors because these measures are used by many companies in the industry as measures of operating and financial performance and are commonly employed by financial analysts and others to evaluate the operating and financial performance of the Partnership from period to period and to compare it with the performance of other publicly traded partnerships within the industry. Adjusted EBITDA and Distributable Cash Flow may not be comparable to a similarly titled measure of other publicly traded limited partnerships or limited liability companies because all entities may not calculate Adjusted EBITDA in the same manner.

The following presents a reconciliation of "Adjusted EBITDA" and "Distributable Cash Flow," both of which are non-GAAP measures, to their nearest comparable GAAP measure. Adjusted EBITDA and Distributable Cash Flow should not be considered as alternatives to GAAP measures, such as net income, operating income, cash flow from operating activities, or any other GAAP measure of financial performance.

Adjusted EBITDA is defined in Legacy's revolving credit facility as net income (loss) plus:

- Interest expense;
- Income taxes;
- Depletion, depreciation, amortization and accretion;
- Impairment of long-lived assets;
- (Gain) loss on sale of partnership investment;

- (Gain) loss on disposal of assets (excluding settlements of asset retirement obligations);
- Equity in (income) loss of partnership;
- Unit-based compensation expense related to LTIP unit awards accounted for under the equity or liability methods; and
- Unrealized (gain) loss on oil and natural gas derivatives.

Table of Contents

Distributable Cash Flow is defined as Adjusted EBITDA less:

- Cash interest expense;
- Cash income taxes;
- Cash settlements of LTIP unit awards; and
- Development capital expenditures.

The following table presents a reconciliation of Legacy’s consolidated net income (loss) to Adjusted EBITDA and Distributable Cash Flow for the years ended December 31, 2011, 2010 and 2009, respectively.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Net income (loss)	$72,061	$10,809	$(92,831)
Plus:			
Interest expense	18,566	25,766	13,222
Income taxes	1,030	537	554
Depletion, depreciation, amortization and accretion	88,178	62,894	58,763
Impairment of long-lived assets	24,510	13,412	9,207
Gain on disposal of assets	—	—	(54)
Equity in income of partnership	(138)	(97)	(31)
Unit-based compensation expense	4,021	5,549	3,130
Unrealized (gain) loss on oil and natural gas derivatives	(6,220)	21,537	128,031
Adjusted EBITDA	$202,008	$140,407	$119,991
Less:			
Cash interest expense	19,044	16,094	17,809
Cash settlements of LTIP unit awards	2,916	2,402	415
Development capital expenditures	71,589	32,917	13,727
Distributable Cash Flow	$108,459	$88,994	$88,040

Capital Resources and Liquidity

Legacy’s primary sources of capital and liquidity have been proceeds from bank borrowings, cash flow from operations, the issuance of additional units or a combination thereof. To date, Legacy’s primary use of capital has been for repayment of bank borrowings and the acquisition and development of oil and natural gas properties.

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 developing additional hydrocarbon 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 revolving credit facility limits our ability to issue additional debt, but permits us to issue unsecured senior or senior subordinated notes. Further, our existing revolving credit facility matures on March 10, 2016.

Our commodity derivatives position, which we use to mitigate commodity price volatility and support our borrowing capacity, contributed $0.6 million of cash settlements in the year ended December 31, 2011. Based upon current oil and natural gas price expectations and our extensive commodity derivatives positions, which cover 66% of our expected production from proved reserves for the year ending December 31, 2012, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility, under which $212.9 million was available for borrowings as of December 31, 2011, will provide us sufficient working capital to meet our planned capital expenditures of $62 million and planned annualized cash distributions of $105.4 million, which reflect the $26.4 million of distributions attributable to the fourth quarter of 2011 that

Table of Contents

were paid in the first quarter of 2012. Our board of directors determines our distribution each quarter and there is no guarantee that the board will maintain or increase our current quarterly distribution rate of $0.55 per unit. Please read "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Legacy's net cash provided by operating activities was $184.2 million and $101.4 million for the year ended December 31, 2011 and 2010, respectively, with the 2011 period being favorably impacted by higher realized oil and natural gas prices and higher sales volumes, partially offset by higher expenses.

Legacy's net cash provided by operating activities was $101.4 million and $37.5 million for the years ended December 31, 2010 and 2009, respectively, with the 2010 period being favorably impacted by higher realized oil and natural gas prices and higher sales volumes, 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, NGL and natural gas prices. Oil, NGL 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, NGLs and natural gas.

Investing Activities

Legacy's cash capital expenditures were $206.1 million for the year ended December 31, 2011. The total includes $134.5 million related to 28 individually immaterial acquisitions and $71.6 million of development projects.

Legacy's cash capital expenditures were $308.9 million for the year ended December 31, 2010. The total includes $125.5 million and $100.8 million for the purchase of producing oil and natural gas properties in the Wyoming and COG Acquisitions, respectively, $49.7 million related to 25 individually immaterial acquisitions and $32.9 million of development projects.

We currently anticipate that our development capital budget, which predominantly consists of drilling, re-completion and well stimulation projects, will be $62 million for the year ending December 31, 2012. Our borrowing capacity under our revolving credit facility is $199.9 million as of February 22, 2012. 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. For instance, approximately 75% of our 2011 developmental capital expenditures were on operated properties. 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 management's current oil and natural gas price expectations for the year ending December 31, 2012, we anticipate that we will have sufficient sources of working capital, from our cash flow from operations and available borrowing capacity under our revolving credit facility, to meet our cash obligations, our planned capital expenditures of $62 million and planned annualized cash distributions of $105.4 million during the year ending December 31, 2012. 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 or planned annualized cash distributions.

We enter into oil, NGL and natural gas derivatives to reduce the impact of oil, NGL and natural gas price volatility on our cash flow. Currently, we use swaps and collars to offset price volatility on NYMEX oil, NGL and Waha, ANR-Oklahoma and CIG-Rockies natural gas prices, which do not include the additional net discount that we typically realize in the Permian Basin. At December 31, 2011, we had in place oil and natural gas derivatives covering significant portions of our estimated 2012 through 2016 oil and natural gas production. As of February 22, 2012 we had derivatives covering approximately 66% of our expected oil and natural gas production for 2012.

Table of Contents

As of February 22, 2012 we had also entered into derivative contracts covering approximately 34% on average of our expected oil and natural gas production for 2013 through 2016 from existing total proved reserves. By removing the price volatility on our cash flows from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow 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. In addition, these counterparties are affiliates of lenders under our revolving credit facility, which allows us to avoid margin calls. Due to the disruptions in the financial markets in recent years, we routinely monitor the creditworthiness of our counterparties.

The following tables summarize, for the periods indicated, our oil and natural gas swaps in place as of February 22, 2012 covering the period from January 1, 2012 through December 31, 2016. We use swaps as a 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 monthly average closing price of the front-month NYMEX WTI oil contract price of oil at Cushing, Oklahoma, and NYMEX West Texas Waha, ANR-Oklahoma and CIG-Rockies prices of natural gas on the average of the three final trading days of the month, and settlement occurs on the fifth day of the production month.

Oil Swaps:

Calendar Year	Annual Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2012(a)	1,950,021	$86.50	$67.72 - $109.20
2013(a)	1,124,243	$85.46	$80.10 - $101.10
2014	586,514	$89.57	$87.50 - $101.10
2015	218,051	$92.18	$90.50 - $100.20
2016	45,600	$94.53	$91.00 - $99.85

(a) On October 6, 2010, as part of an oil swap transaction entered into with a counterparty, we sold two call options to the counterparty that allow the counterparty to extend a swap transaction covering calendar year 2011 to either 2012, 2013 or both calendar years. The counterparty exercised the option covering calendar year 2012 on December 30, 2011 and must exercise or decline the option covering calendar year 2013 on December 31, 2012. As the option was exercised for calendar year 2012, we will pay the counterparty floating prices and receive a fixed price of $98.25 on annual notional volumes of 183,000 Bbls. For calendar year 2013, if exercised, we would pay the counterparty floating prices and receive a fixed price of $98.25 on annual notional volumes of 182,500 Bbls in 2013. The premium paid by the counterparty for the two call options was paid to us in the form of an increase in the fixed price that we received pursuant to the 2011 swap of $98.25 per Bbl on 182,500 Bbls, or 500 Bbls per day, rather than the prevailing market price of approximately $87.00 per Bbl. These additional potential volumes related to the unexercised 2013 option are not reflected in the above table.

Natural Gas Swaps:

Calendar Year	Annual Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2012	4,772,990	$6.07	$4.19 - $8.70
2013	3,630,654	$5.62	$4.68 - $6.89

2014	2,091,254	$5.63	$4.95 - $6.47
2015	1,339,300	$5.65	$5.14 - $5.82
2016	219,200	$5.30	$5.30

Table of Contents

On June 24, 2008, we entered into a NYMEX West Texas Intermediate oil derivative collar contract that combines a long put option or "floor" with a short call option or "ceiling." The following table summarizes the oil collar contract currently in place as of February 22, 2012, covering the period from January 1, 2012 through December 31, 2012:

Calendar Year	Volumes (Bbls)	Floor Price	Ceiling Price
2012	65,100	$120.00	$156.30

On January 12, 2011, we entered into a West Texas Waha natural gas derivative collar contract that combines a long put option or "floor" with a short call option or "ceiling." The following table summarizes the natural gas collar contract currently in place as of February 22, 2012, covering the period from January 1, 2012 through December 31, 2012:

Calendar Year	Volumes (MMBtu)	Floor Price	Ceiling Price
2012	360,000	$4.00	$5.45

We have also entered into multiple NYMEX West Texas Intermediate crude oil derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the short put allows us to buy a put and sell a call at higher prices thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk. If the market price is below the long put fixed price but above the short put fixed price, a three-way collar allows us to settle for the long put fixed price. A three-way collar also allows us to settle for WTI market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. In regards to our three-way collar contracts, if the market price has fallen below the short put fixed price, we would receive the market price plus either $25 or $30 per barrel, depending on the contract. The following table summarizes the three-way oil collar contracts currently in place as of February 22, 2012:

Calendar Year	Volumes (Bbls)	Average Short Put	Average Long Put	Average Short Call
2012	384,600	$67.86	$94.29	$113.16
2013	726,920	$65.41	$91.16	$111.82
2014	847,130	$64.85	$90.17	$116.08
2015	824,300	$65.31	$90.31	$118.85
2016	219,100	$66.23	$91.23	$116.65

The following table details the commodity derivative assets (liabilities), by commodity, as of December 31, 2011 and 2010:

	Oil Swaps	Oil Collar	Three-Way Oil Collars	Oil Swaption	Natural Gas Swaps	Natural Gas Collar	Total
	(In thousands)						
Balance December 31, 2010	$(39,304)	$3,954	$(1,118)	$3,259	$18,545	$—	$(14,664)
Balance December 31, 2011	$(38,497)	$1,672	$4,760	$(1,842)	$25,132	$332	$(8,443)

Table of Contents

The following table details the commodity derivative income (expense) activities, by commodity, for the year ended December 31, 2011:

	Oil Swaps	Oil Collar	Three-Way Oil Collar	Oil Swaption	Natural Gas Swaps	Natural Gas Collar	Total
	(In thousands)						
Realized gain/(loss) on cash settlements	$(13,096)	$1,761	$—	$—	$11,972	$—	$637
Unrealized gain/(loss) on mark-to-market of derivatives existing as of January 1, 2011	(1,661)	(393)	750	(5,101)	(1,653)	—	(8,058)
Unrealized gain on mark-to-market of derivatives entered into during 2011	578	—	5,128	—	8,240	332	14,278
Realized and unrealized gain/(loss) on derivatives	$(14,179)	$1,368	$5,878	$(5,101)	$18,559	$332	$6,857

Financing Activities

Legacy’s net cash provided by financing activities was $22.3 million for the year ended December 31, 2011, compared to $183.1 million for the year ended December 31, 2010. During the year ended December 31, 2011, total net borrowings under our revolving credit facility were $12.0 million, comprised of borrowings of $356.0 million and repayments of $344.0 million. Our November 2011 public equity offering and our Equity Distribution Agreement yielded net cash proceeds of $109.0 million, which were used to pay down our balance on our revolving credit facility. Additionally, Legacy had cash outflow during the year ended December 31, 2011 in the amount of $93.6 million for distributions to unitholders. Cash provided by financing activities during the year ended December 31, 2010, included $88.0 million in net borrowings under our revolving credit facility, $179.1 million in net cash proceeds from our January and November 2010 public equity offerings and $83.5 million for distributions to unitholders.

Our Revolving Credit Facility

Previous Credit Agreement

On March 27, 2009, we entered into a three-year $600 million secured revolving credit facility (the "Previous Credit Agreement") and retained BNP Paribas as administrative agent to replace our initial four year, $300 million revolving credit facility with BNP Paribas as administrative agent. All borrowings outstanding under the Previous Credit Agreement were paid in full on March 10, 2011 with borrowings under the Current Credit Agreement.

Current Credit Agreement

On March 10, 2011, we entered into an amended and restated five-year, $1 billion secured revolving credit facility with BNP Paribas as administrative agent (the "Current Credit Agreement"). Our obligations under the revolving credit facility are secured by mortgages on more than 80% of our oil and natural gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. Borrowings under the Current Credit Agreement mature on March 10, 2016. The amount available for borrowing at any one time is limited to the borrowing base, originally set at $500 million, currently at $550 million, with a $2 million sub-limit for letters of credit. The borrowing base is subject to semi-annual redeterminations on April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. We also have the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural 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 (currently 13 member banks), and any decrease in the borrowing base must be approved by the lenders holding at least 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the revolving 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

Table of Contents

lenders holding 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the revolving 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 natural gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral. Legacy may at any time issue up to $500 million in aggregate principal amount of senior notes or new debt whose proceeds are used to refinance such senior notes, subject to specified conditions in the Current Credit Agreement, which include that upon the issuance of such senior notes or new debt, the borrowing base shall be reduced by an amount equal to (i) in the case of senior notes, 25% of the stated principal amount of the senior notes and (ii) in the case of new debt, 25% of the portion of the new debt that exceeds the principal amount of the senior notes. Also, notwithstanding that a lender (or its affiliate) is no longer a party to the Current Credit Agreement, any lender (or its affiliate) which has entered into any hedging arrangement with us while a party to the Current Credit Agreement will continue to have our obligations under such hedging arrangement secured on a ratable and pari passu basis by the collateral securing our obligations under the Current Credit Agreement, the related loan documents and our hedging arrangements.

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 highest of the prime rate, the Federal funds effective rate plus 0.50%, or the one-month London interbank rate (“LIBOR”) plus 1.00%, plus an applicable margin ranging from and including 0.75% and 1.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn, or

- with respect to any Eurodollar loans, one-, two-, three- or six-month LIBOR plus an applicable margin ranging from and including 1.75% and 2.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

We pay a commitment fee equal to 0.50% on the average daily amount of the unused amount of the commitments under the Current Credit Agreement, payable quarterly.

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

Our Current Credit Agreement 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 our business; or

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

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

- total debt as of the last day of the most recent quarter to EBITDA (as defined in the Current Credit Agreement) in total over the last four quarters of not more than 4.0 to 1.0; and

- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC 815, which includes the current portion of oil, natural gas and interest rate derivatives.

Table of Contents

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 10, 2011 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's ceasing to be our sole general partner;
- the entry of, and failure to pay, one or more adverse judgments in excess of $2.0 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 $2.0 million in any year.

As of December 31, 2011, Legacy was in compliance with all financial and other covenants of the revolving credit facility.

Off-Balance Sheet Arrangements

None.

Table of Contents

Contractual Obligations

A summary of our contractual obligations as of December 31, 2011 is provided in the following table.

Contractual Cash Obligations	Obligations Due in Period				
	2012	2013-2014	2015-2016	Thereafter	Total
	(In thousands)				
Long-term debt(a)	$—	$—	$337,000	$—	$337,000
Interest on long-term debt(b)	8,998	17,996	10,719	—	37,713
Derivative obligations(c)	11,787	12,136	—	30	23,953
Management compensation(d)	1,477	2,954	2,954	—	7,385
Asset retirement obligation(e)	20,262	3,996	2,842	93,174	120,274
Office lease	506	1,044	351	—	1,901
Total contractual cash obligations	$43,030	$38,126	$353,866	$93,204	$528,226

(a) Represents amounts outstanding under our revolving credit facility as of December 31, 2011.

(b) Based upon our weighted average interest rate of 2.67% under our revolving credit facility as of December 31, 2011.

(c) Derivative obligations represent net liabilities for commodity and interest rate derivatives that were valued as of December 31, 2011, 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” for additional information regarding our derivative obligations.

(d) The related employment agreements do not contain termination provisions; therefore, the ultimate payment obligation is not known. For purposes of this table, management has not reflected payments subsequent to 2016.

(e) Asset retirement obligations of oil and natural gas assets, excluding salvage value and accretion, the ultimate settlement and timing of which cannot be precisely determined in advance.

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. We based our 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 Consolidated Financial Statements for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

Table of Contents

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 prepares a reserve and economic evaluation of all our properties in accordance with Securities and Exchange Commission, or "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. In addition, 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, 2011 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. US GAAP 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 effective credit-adjusted-risk-free rate for each layer. Should either the estimated life or the estimated abandonment costs of a property change materially upon our periodic 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. 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. Any difference in the cost to plug and the related liability is recorded as a gain or loss on our income statement in the disposal of assets line item.

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 present value calculation, could differ from actual results, despite our efforts to make an accurate estimate. We engage independent engineering firms to evaluate our properties annually. We consider 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.

Nature of Critical Estimate Item: Derivative Instruments and Hedging Activities — We 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, swaptions and collars whereby we exchange our floating price for our oil and natural gas for a fixed price and floating interest rates for fixed rates with qualified and creditworthy counterparties. Our existing oil swaps, natural gas swaps, interest rate swaps, oil swaptions and oil and natural gas collars are with members of our lending group which enables us to avoid margin calls for out-of-the-money 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. We use estimate market values utilizing software provided by a third party firm, which specializes in valuing derivatives, and validate these estimates by comparison to counterparty estimates as the basis for these end-of-period mark-to-market adjustments. In order to estimate market values, we use forward commodity price curves, if available, or estimates of forward curves provided by third party pricing experts. For our interest rate swaps, we use a yield curve based on money market rates and interest swap rates to estimate market value. 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 periods. As shown in the previous tables, we have hedged a significant portion of our future production through 2016. Taking into account the mark-to-market liabilities and assets recorded as of December 31, 2011, 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.

Recently Issued Accounting Pronouncements

None

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 and the supply of oil outside of the United States.

We periodically enter into and anticipate entering into derivative arrangements with respect to a portion of our projected oil and natural gas production through various transactions that offset changes in the future prices received. These transactions may include price swaps, collars, three-way collars and swaptions. These derivative 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, 2011, the fair market value of Legacy's commodity derivative positions was a net liability of $8.4 million. As of December 31, 2010, the fair market value of Legacy's commodity derivative positions was a net liability of $14.7 million. We routinely monitor the credit default risk of our counterparties via risk monitoring services. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives for 2012 through December 31, 2016, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Investing Activities."

If oil prices decline by $1.00 per Bbl, then the standardized measure of our combined proved reserves as of December 31, 2011 would decline from $1,140.4 million to $1,123.5 million, or 1.5%. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of our combined proved reserves as of December 31, 2011 would decline from $1,140.4 million to $1,133.7 million, or 0.6%. However, larger decreases in oil and natural gas prices may have a proportionately greater impact on our standardized measure.

Interest Rate Risks

At December 31, 2011, Legacy had debt outstanding of $337 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for the year ended December 31, 2011 was 3.05%. A 1% increase in LIBOR on Legacy's outstanding debt as of December 31, 2011 would not have an effect on annual interest expense, as Legacy has entered into interest rate swaps to mitigate the volatility of interest rates, that expire between April 2013 and November 2015, on $364 million of floating rate debt, which exceeds the current outstanding debt balance, to a weighted-average fixed rate of 2.17%. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Conditions sometimes arise where actual borrowings are less than notional amounts hedged which has and could result in overhedged amounts.

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.

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

None.

ITEM 9A. 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, as amended, 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, 2011. 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 provide reasonable assurance that such 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

Table of Contents

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.

Effective January 1, 2011, we implemented a new accounting system in conjunction with a transition to bring our back-office accounting functions in-house from an outsourced third-party. While these transitions have changed the physical location within the accounting process where certain internal control points occur, including our IT general controls, the nature and extent of such internal controls remain unchanged. Further, there have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended December 31, 2011, 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 control over financial reporting. Our internal control over financial reporting is a process designed by, or under the supervision of, our general partner's Chief Executive Officer and Chief Financial Officer, and effected by the board of directors of our general partner, management and other personnel, 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. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and the board of directors of our general partner; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 and procedures may deteriorate.

As of December 31, 2011, 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, 2011, based on those criteria.

BDO USA, LLP, the independent registered public accounting firm who also audited our Consolidated Financial Statements included in this Annual Report on Form 10-K, has issued an attestation report on our internal control over financial reporting as of December 31, 2011, which is set forth below under "Attestation Report."

55

Table of Contents

Attestation Report

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

We have audited Legacy Reserves LP's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Legacy Reserves LP's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Item 9A. Controls and Procedures - Management's Annual Report on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on Legacy Reserves LP's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Legacy Reserves LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Legacy Reserves LP as of December 31, 2011 and 2010, and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2011, and our report dated February 23, 2012 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 23, 2012

Table of Contents

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 2012 annual meeting of unitholders under the headings "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 not later than 120 days after December 31, 2011.

ITEM 11. EXECUTIVE COMPENSATION

We intend to include information with respect to executive compensation in Legacy's definitive proxy statement for its 2012 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, 2011.

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 2012 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, 2011.

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 2012 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, 2011.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

We intend to include information regarding principal accountant fees and services in Legacy's definitive proxy statement for its 2012 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, 2011.

Table of Contents

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 Agreement 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, 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)
3.6	—	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC
4.1	—	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)
4.2	—	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)
4.3	—	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)
10.1	—	Second Amended and Restated Credit Agreement dated as of March 10, 2011 among Legacy Reserves LP, as borrower, BNP Paribas, as administrative agent, Wells Fargo Bank, N.A., as syndication agent, Compass Bank, as documentation agent, and the Lenders party thereto (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed March 17, 2011, Exhibit 10.1)
10.2	—	First Amendment to Second Amended and Restated Credit Agreement among Legacy Reserves LP, as borrower, the Guarantors, BNP Paribas, as administrative agent, and the Lenders Signatory Hereto dated as of September 30, 2011(Incorporated by reference to Legacy Reserves LP's quarterly report on Form

10-Q (File No. 001-33249) filed November 4, 2011, Exhibit 10.1)

58

Table of Contents

Exhibit Number			Description
10.3	†	—	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)
10.4	†	—	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)
10.5	†	—	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)
10.6	†	—	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)
10.7	†	—	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)
10.8	†	—	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)
10.9	†	—	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)
10.10	†	—	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)
10.11	†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Cary D. Brown and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K filed December 31, 2008, Exhibit 10.1)
10.12	†	—	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)
10.13	†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Steven H. Pruett and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K filed December 31, 2008, Exhibit 10.2)
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	†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K filed December 31, 2008, Exhibit 10.3)
10.16	†	—	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)
10.17	†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K filed December 31, 2008, Exhibit 10.4)
10.18	†	—	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)
10.19	†	—	

Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between William M. Morris and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K filed December 31, 2008, Exhibit 10.5)

Table of Contents

Exhibit Number		Description
10.20	—	Purchase and Sale Agreement dated November 5, 2010, by and between COG Operating LLC and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed March 4, 2011, Exhibit 10.23)
10.21†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Objective) (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K filed February 24, 2010, Exhibit 99.1)
10.22†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Subjective) (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K filed February 24, 2010, Exhibit 99.2)
10.23	—	Equity Distribution Agreement, dated August 25, 2011, by and among the Partnership and Knight Capital Americas, L.P. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed August 25, 2011, Exhibit 1.1)
21.1*	—	List of subsidiaries of Legacy Reserves LP
23.1*	—	Consent of BDO USA, 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)
99.1*	—	Summary Reserve Report from LaRoche Petroleum Consultants, Ltd.

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* Filed herewith

† Management contract or compensatory plan or arrangement

Table of Contents

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, on the 23rd day of February, 2011.

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)

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Cary D. Brown and Steven H. Pruett, or either of them, each with power to act without the other, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all subsequent amendments and supplements to this Annual Report on Form 10-K, and to file the same, or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby qualifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this annual report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/S/ CARY D. BROWN Cary D. Brown	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 23, 2012
/S/ STEVEN H. PRUETT Steven H. Pruett	President, Chief Financial Officer and Secretary (Principal Financial Officer)	February 23, 2012
/S/ WILLIAM M. MORRIS William M. Morris	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2012
/S/ KYLE A. MCGRAW Kyle A. McGraw	Executive Vice President and Director	February 23, 2012
/S/ DALE A. BROWN Dale A. Brown	Director	February 23, 2012
/S/ WILLIAM R. GRANBERRY William R. Granberry	Director	February 23, 2012

/S/ G. LARRY LAWRENCE G. Larry Lawrence	Director	February 23, 2012
/S/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 23, 2012
/S/ KYLE D. VANN Kyle D. Vann	Director	February 23, 2012

Table of Contents

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

Report of Independent Registered Public Accounting Firm

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

We have audited the accompanying consolidated balance sheets of Legacy Reserves LP as of December 31, 2011 and 2010 and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of Legacy Reserves LP's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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, 2011 and 2010 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Legacy Reserves LP's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 23, 2012 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 23, 2012

Table of Contents

LEGACY RESERVES LP

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2011 AND 2010

	2011	2010
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$3,151	$3,478
Accounts receivable, net:		
Oil and natural gas	35,489	27,050
Joint interest owners	10,299	10,378
Other	204	91
Fair value of derivatives (Notes 8 and 9)	7,117	7,763
Prepaid expenses and other current assets	3,525	1,838
Total current assets	59,785	50,598
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	1,389,326	1,174,498
Unproved properties	20,063	12,543
Accumulated depletion, depreciation, amortization and impairment	(450,060)	(343,205)
	959,329	843,836
Other property and equipment, net of accumulated depreciation and amortization of $3,530 and $2,437, respectively	3,310	2,917
Deposits on pending acquisitions	—	112
Operating rights, net of amortization of $3,034 and $2,529, respectively	3,983	4,488
Fair value of derivatives (Notes 8 and 9)	10,188	4,000
Other assets, net of amortization of $6,337 and $4,809, respectively	6,611	3,331
Investment in equity method investee	282	144
Total assets	$1,043,488	$909,426
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$3,286	$631
Accrued oil and natural gas liabilities	45,351	29,654
Fair value of derivatives (Notes 8 and 9)	18,905	14,882
Asset retirement obligation (Note 11)	20,262	18,333
Other (Notes 8 and 13)	9,646	9,455
Total current liabilities	97,450	72,955
Long-term debt (Note 3)	337,000	325,000
Asset retirement obligation (Note 11)	100,012	92,929
Fair value of derivatives (Notes 8 and 9)	18,897	25,540
Other long-term liabilities	1,794	1,263
Total liabilities	555,153	517,687
Commitments and contingencies (Note 6)		
Unitholders' equity:		
Limited partners' equity — 47,801,682 and 43,528,776 units issued and outstanding at December 31, 2011 and 2010, respectively	488,264	391,700
General partner's equity (approximately 0.04%)	71	39

Total unitholders’ equity	488,335	391,739
Total liabilities and unitholders’ equity	$1,043,488	$909,426

See accompanying notes to consolidated financial statements.

Table of Contents

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	2011	2010	2009
	(In thousands, except per unit data)		
Revenues:			
Oil sales	$264,473	$172,754	$103,319
Natural gas liquids (NGL) sales	18,888	13,670	11,565
Natural gas sales	53,524	29,965	22,395
Total revenues	336,885	216,389	137,279
Expenses:			
Oil and natural gas production	96,914	69,228	48,814
Production and other taxes	20,329	12,683	8,145
General and administrative	23,084	19,265	15,502
Depletion, depreciation, amortization and accretion	88,178	62,894	58,763
Impairment of long-lived assets	24,510	13,412	9,207
(Gain) loss on disposal of assets	(625)	592	378
Total expenses	252,390	178,074	140,809
Operating income (loss)	84,495	38,315	(3,530)
Other income (expense):			
Interest income	15	10	9
Interest expense (Notes 3, 8 and 9)	(18,566)	(25,766)	(13,222)
Equity in income of partnership	138	97	31
Realized and unrealized net gains (losses) on commodity derivatives (Notes 8 and 9)	6,857	(1,400)	(75,554)
Other	152	90	(11)
Income (loss) before income taxes	73,091	11,346	(92,277)
Income tax expense	(1,030)	(537)	(554)
Net income (loss)	$72,061	$10,809	$(92,831)
Income (loss) per unit — basic and diluted (Note 12)	$1.63	$0.27	$(2.89)
Weighted average number of units used in computing net income (loss) per unit —			
Basic	44,093	40,233	32,163
Diluted	44,112	40,237	32,163

See accompanying notes to consolidated financial statements.

Table of Contents

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders' Equity
	(In thousands)			
Balance, December 31, 2008	31,049	$380,439	$194	$380,633
Units issued to Legacy Board of Directors for services	16	259	—	259
Compensation expense on restricted unit awards issued to employees	—	103	—	103
Vesting of restricted units	20	—	—	—
Net proceeds from equity offering	3,795	57,221	—	57,221
Redemption of investment from MBN Operating LP	—	—	(81)	(81)
Distributions to unitholders, $2.08 per unit	—	(66,616)	(28)	(66,644)
Net loss	—	(92,779)	(52)	(92,831)
Balance, December 31, 2009	34,880	278,627	33	278,660
Units issued to Legacy Board of Directors for services	11	226	—	226
Compensation expense on restricted unit awards issued to employees	—	516	—	516
Vesting of restricted units	3	—	—	—
Net proceeds from equity offerings	8,338	179,053	—	179,053
Units issued in exchange for oil and natural gas properties	297	5,959	—	5,959
Net distributions to unitholders, $2.08 per unit	—	(83,484)	—	(83,484)
Net income	—	10,803	6	10,809
Balance, December 31, 2010	43,529	391,700	39	391,739
Units issued to Legacy Board of Directors for services	18	500	—	500
Compensation expense on restricted unit awards issued to employees	—	956	—	956
Vesting of restricted units	30	—	—	—
Net proceeds from equity offerings	3,947	108,956	—	108,956
Units issued in exchange for oil and natural gas properties	278	7,714	—	7,714
Net distributions to unitholders, $2.14 per unit	—	(93,591)	—	(93,591)
Net income	—	72,029	32	72,061
Balance, December 31, 2011	47,802	$488,264	$71	$488,335

See accompanying notes to consolidated financial statements.

Table of Contents

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	2011	2010	2009
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$72,061	$10,809	$(92,831)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	88,178	62,894	58,763
Amortization of debt issuance costs	1,528	2,023	1,646
Impairment of long-lived assets	24,510	13,412	9,207
(Gain) loss on derivatives	(8,800)	8,728	71,764
Equity in income of partnership	(138)	(97)	(37)
Unit-based compensation	1,106	3,146	2,728
(Gain) loss on disposal of assets	(625)	592	378
Changes in assets and liabilities:			
Increase in accounts receivable, oil and natural gas	(8,439)	(8,980)	(5,872)
(Increase) decrease in accounts receivable, joint interest owners	79	(5,831)	2,718
(Increase) decrease in accounts receivable, other	(113)	273	(304)
(Increase) decrease in other current assets	(1,382)	389	1,859
Increase (decrease) in accounts payable	2,655	(949)	(4,370)
Increase (decrease) in accrued oil and natural gas liabilities	15,697	15,764	(3,310)
Decrease in other liabilities	(2,080)	(802)	(4,863)
Total adjustments	112,176	90,562	130,307
Net cash provided by operating activities	184,237	101,371	37,476
Cash flows from investing activities:			
Investment in oil and natural gas properties	(206,080)	(308,883)	(22,389)
(Increase) decrease in deposit on pending acquisition	112	6,388	(6,500)
Proceeds from sale of assets	—	—	51
Investment in other equipment	(1,485)	(2,394)	(345)
Goodwill	—	(494)	—
Net cash settlements on commodity derivatives	637	20,137	52,477
Net cash provided by (used in) investing activities	(206,816)	(285,246)	23,294
Cash flows from financing activities:			
Proceeds from long-term debt	356,000	369,000	61,000
Payments of long-term debt	(344,000)	(281,000)	(106,000)
Payments of debt issuance costs	(5,113)	(433)	(4,549)
Proceeds from issuance of units, net	108,956	179,053	57,221
Redemption of investment from MBN Operating LP	—	—	(81)
Distributions to unitholders	(93,591)	(83,484)	(66,644)
Net cash provided by (used in) financing activities	22,252	183,136	(59,053)
Net increase (decrease) in cash and cash equivalents	(327)	(739)	1,717
Cash and cash equivalents, beginning of period	3,478	4,217	2,500
Cash and cash equivalents, end of period	$3,151	$3,478	$4,217
Non-Cash Investing and Financing Activities:			
Asset retirement obligation costs and liabilities	$253	$7,248	$182
Asset retirement obligations associated with property acquisitions	$8,300	$17,618	$3,505

Units issued in exchange for oil and natural gas properties	$7,714	$5,959	$—

See accompanying notes to consolidated financial statements.

Table of Contents

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

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

Legacy Reserves LP ("LRLP," "Legacy" or the "Partnership") 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 currently owns an approximately 0.04% 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 66 2/3 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.

Legacy owns and operates oil and natural gas producing properties located primarily in the Permian Basin of West Texas and southeast New Mexico, the Texas Panhandle and the Mid-Continent and Rocky Mountain regions of the United States. Legacy has acquired oil and natural gas producing properties and drilled leasehold.

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.

(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. Accounts are written off 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 using the successful efforts method. Under this method of accounting, costs relating to the acquisition 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.

Depreciation and depletion of producing oil and natural gas properties is recorded based on units of production. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (wells and related equipment and facilities) are amortized on the basis of proved developed reserves. As more fully described below, proved reserves are estimated annually by Legacy’s independent petroleum engineer, LaRoche Petroleum Consultants, Ltd. ("LaRoche"), 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, 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 compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management’s expectations of future oil and natural gas prices. These future price scenarios reflect Legacy’s estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows based on management’s expectations of future oil and natural gas prices. For the year ended December 31, 2011, Legacy recognized $24.5 million of impairment expense on 70 separate producing fields related primarily to the decline in realized natural gas prices during the year combined with rising operating costs on select fields which reduced the estimated future cash flows for these fields. For the year ended December 31, 2010, Legacy recognized $13.4 million of impairment expense on 67 separate producing fields related primarily to the decline in realized natural gas prices during the year combined with rising operating costs on select fields which reduced the estimated future cash flows for these fields as well as the write-off of PUDs in one field and single well performance declines in two other fields. For the year ended December 31, 2009, Legacy recognized $9.2 million of impairment expense on 20 separate producing fields related primarily to the decline in realized natural gas prices during the year combined with rising operating costs on select fields as well as an unsuccessful re-completion activity in one field which reduced the estimated future cash flows for these fields.

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, NGLs and Natural Gas Reserve Quantities

Legacy’s estimate of proved reserves is based on the quantities of oil, NGLs 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 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. The estimate of Legacy's proved reserves as of December 31, 2011, 2010 and 2009 have been prepared and presented in accordance with SEC rules and accounting standards.

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'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, NGLs and natural gas 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 margin-based franchise tax law that replaced the existing franchise tax. This 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 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 became effective for franchise tax reports due on or after January 1, 2008.

Legacy recorded income tax expense of $1.0 million, $0.5 million and $0.6 million for the years ended December 31, 2011, 2010 and 2009, respectively, 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 Partnership's book basis in its net assets exceeds the Partnership's net tax basis by $619 million at December 31, 2011.

(g) Derivative Instruments and Hedging Activities

Legacy uses derivative financial instruments to achieve more predictable cash flows by reducing its exposure to oil, NGL and natural gas price fluctuations and interest rate changes. 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 rates. Therefore, Legacy records the change in the fair market values of oil, NGL and natural gas derivatives in current earnings. Changes in the fair values of interest rate derivatives 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 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, asset retirement obligations and accrued revenues.

(i) Revenue Recognition

Sales of crude oil, NGLs 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.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as "Accounts receivable - oil and natural gas" in the accompanying consolidated balance sheets.

Legacy 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, when 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, 2011, 2010 and 2009.

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 natural gas properties. 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 2012, 2013, 2014, 2015 and 2016 is $497,000, $493,000, $484,000, $444,000 and $417,000, respectively.

(l) Environmental

Legacy is subject to extensive federal, state and local environmental laws and regulations. These laws, which are frequently 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 is fixed and readily determinable.

(m) Income (Loss) Per Unit

Basic income (loss) per unit amounts are calculated using the weighted average number of units outstanding during each period. Diluted income (loss) per unit also give effect to dilutive unvested restricted units (calculated based upon the treasury stock method) (see Note 12).

(n) Redemption of Units

Units redeemed are recorded at cost.

(o) Segment Reporting

Legacy's management initially 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 its formation on March 15, 2006, a Long-Term Incentive Plan ("LTIP") for Legacy was created. Due to Legacy's history of cash settlements for option exercises, Legacy accounts for unit options under the liability method which requires the Partnership to recognize the fair value of each unit option at the end of each period. Expense or benefit is recognized as the fair value of the liability changes from period to period. Legacy's issued units, as reflected in the accompanying consolidated balance sheet at December 31, 2011, do not include 105,497 units related to unvested restricted unit awards.

(q) Accrued Oil and Natural Gas Liabilities

Below are the components of accrued oil and natural gas liabilities as of December 31, 2011 and 2010.

	December 31,	
	2011	2010
	(In thousands)	
Revenue payable to joint interest owners	$19,972	$12,611
Accrued lease operating expense	8,004	4,119
Accrued capital expenditures	6,920	6,010
Accrued ad valorem tax	5,171	2,516
Other	5,284	4,398
	$45,351	$29,654

(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.

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.

Long-term incentive plan obligations. See Note 13 for discussion of process used in estimating the fair value of the long-term incentive plan obligations.

Derivatives. See Note 8 for discussion of process used in estimating the fair value of commodity price and interest rate derivatives.

(3) Credit Facility

Previous Credit Agreement: On March 27, 2009, Legacy entered into a three-year secured revolving credit facility with BNP Paribas as administrative agent (the “Previous Credit Agreement”). Borrowings under the Previous Credit Agreement were set to mature on April 1, 2012. The Previous Credit Agreement permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $600 million. The borrowing base under the Previous Credit Agreement, initially set at $340 million, was increased to $410 million on March 31, 2010. Under the Previous Credit Agreement, interest on debt outstanding was charged based on Legacy’s selection of a LIBOR rate plus 2.25% to 3.0%, or the alternate base rate (“ABR”) which equaled the highest of the prime rate, the Federal funds effective rate plus 0.50% or LIBOR plus 1.50%, plus an applicable margin between 0.75% and 1.50%.

Current Credit Agreement: On March 10, 2011, Legacy entered into an amended and restated five-year $1 billion secured revolving credit facility with BNP Paribas as administrative agent, as amended effective September 30, 2011 (the "Current Credit Agreement"). Borrowings under the Current Credit Agreement mature on March 10, 2016. The amount available for borrowing at any one time is limited to the borrowing base, with a $2 million sub-limit for letters of credit. The borrowing base under the Current Credit Agreement, initially set at $500 million, was redetermined and increased to $535 million on September 30, 2011 and subsequently increased further to $550 million in conjunction with the closing of an acquisition of producing oil and natural gas properties in the Permian Basin on November 14, 2011. 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-determine the borrowing base between scheduled re-determinations. Legacy also has the right, once during each calendar year, to request the re-determination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base. Under the Current Credit Agreement, interest on debt outstanding is charged based on Legacy's selection of a one-, two-, three- or six-month LIBOR rate plus 1.75% to 2.75%, or the ABR which equals the highest of the prime rate, the Federal funds effective rate plus 0.50% or one-month LIBOR plus 1.00%, plus an applicable margin from 0.75% to 1.75% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

The borrowing base permits Legacy to issue up to $500 million in aggregate principal amount of senior notes or new debt issued to refinance senior notes, subject to specified conditions in the Current Credit Agreement, which include that upon the issuance of such senior notes or new debt, the borrowing base will be reduced by an amount equal to (i) in the case of senior notes, 25% of the stated principal amount of the senior notes and (ii) in the case of new debt, 25% of the portion of the new debt that exceeds the original principal amount of the senior notes.

As of December 31, 2011, Legacy had outstanding borrowings of $337 million at a weighted average interest rate of 2.67%. Thus, Legacy had approximately $213 million of availability remaining. For the year ended December 31, 2011, Legacy paid $11.7 million