LEGACY RESERVES LP
Form 424B5
September 15, 2009

Filed pursuant to Rule 424(b)(5)
Registration No. 333-150111

PROSPECTUS SUPPLEMENT
(To the Prospectus Dated April 16, 2008)

3,300,000 Units

LEGACY RESERVES LP
Representing Limited Partner Interests

We are selling 3,300,000 units representing limited partner interests of Legacy Reserves LP. Our units trade on the NASDAQ Global Select Market under the symbol LGCY. The last reported sales price of our units on the NASDAQ Global Select Market on September 14, 2009 was $16.87 per unit.

Investing in our units involves risks. You should carefully consider each of the factors described under Risk Factors beginning on page S-11 of this prospectus supplement and on page 5 of the accompanying prospectus.

	Per Unit	Total
Public Offering Price	$ 15.85	$ 52,305,000
Underwriting Discounts and Commissions	$ 0.67	$ 2,211,000
Proceeds, Before Expenses, to Legacy Reserves LP	$ 15.18	$ 50,094,000

The underwriters expect to deliver the units on or about September 18, 2009.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement or the accompanying prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

We have granted the underwriters a 30-day option to purchase up to an additional 495,000 units from us on the same terms and conditions as set forth above if the underwriters sell more than 3,300,000 units in this offering.

Joint Book-Running Managers

Wells Fargo Securities **Raymond James** **RBC Capital Markets**

Co-Managers

Oppenheimer & Co.	**Stifel Nicolaus**	**Wunderlich Securities**

The date of this prospectus supplement is September 15, 2009.

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PROSPECTUS SUPPLEMENT

PROSPECTUS DATED APRIL 16, 2008

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Important Notice About Information in This Prospectus Supplement and the Accompanying Prospectus

This document is in two parts. The first part is the prospectus supplement, which describes the specific terms of this offering and also adds to and updates information contained in the accompanying prospectus and the documents incorporated by reference into this prospectus supplement and the accompanying prospectus. The second part is the accompanying prospectus, which gives more general information about securities we may offer from time to time, some of which may not apply to this offering of units.

If the information relating to the offering varies between the prospectus supplement and the accompanying prospectus, you should rely on the information in this prospectus supplement.

You should rely only on the information contained in or incorporated by reference in this prospectus supplement, the accompanying prospectus or any free writing prospectus prepared by or on behalf of us. We have not, and the underwriters have not, authorized anyone to provide you with additional or different information. If anyone provides you with additional, different or inconsistent information, you should not rely on it. This prospectus supplement and accompanying prospectus are not an offer to sell or a solicitation of an offer to buy our units in any jurisdiction where such offer or any sale would be unlawful. You should not assume that the information contained in this prospectus supplement or the accompanying prospectus is accurate as of any date other than the date on the front of those documents or that any information we have incorporated by reference is accurate as of any date other than the date of the document incorporated by reference. Our business, financial condition, results of operations and prospects may have changed since such dates.

The information in this prospectus supplement is not complete. You should review carefully all of the detailed information appearing in this prospectus supplement, the accompanying prospectus and the documents we have incorporated by reference before making any investment decision.

SUMMARY

This summary highlights information included or incorporated by reference in this prospectus supplement. It does not contain all of the information that may be important to you. You should read carefully the entire prospectus supplement, the accompanying prospectus, the documents incorporated by reference and the other documents to which we refer herein for a more complete understanding of this offering.

Unless the context otherwise requires, references to Legacy Reserves, Legacy, we, our, us, or like terms prior to March 15, 2006 refer to the Moriah Group, Legacy Reserves LP s predecessor, including the oil and natural gas properties we acquired in exchange for units and cash from the Moriah Group, the Brothers Group, H2K Holdings, MBN Properties, our Founding Investors, as discussed in Note 4 to the Consolidated Financial Statements of our Annual Report on Form 10-K for the year ended December 31, 2008 incorporated by reference herein, and certain charitable foundations in connection with our private equity offering on March 15, 2006. When used for periods from March 15, 2006 forward, those terms refer to Legacy Reserves LP and its subsidiaries.

LEGACY RESERVES LP

Overview

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

Our primary business objective is to generate stable cash flows allowing us to make cash distributions to our unitholders and to 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.

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

Our oil and natural gas production and reserve data as of December 31, 2008 are as follows:

- We had proved reserves of approximately 30.8 MMBoe, of which 68% were oil and natural gas liquids and 89% were classified as proved developed producing, 2% were proved developed non-producing, and 9% were proved undeveloped;

- Our proved reserves had a standardized measure of $235.0 million based on a price of $41.00 per barrel of oil and a price of $5.71 per MMBtu of natural gas held constant over the remaining life of the properties; and

- Our proved reserves to production ratio was approximately 10 years based on our average daily net production of 8,553 Boe/d for the three months ended December 31, 2008.

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;

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Maintain financial flexibility; and

Reduce commodity price risk through oil, NGL and natural gas derivative transactions.

Competitive Strengths

We believe that we are positioned to successfully execute our business strategy because of the following competitive strengths:

Proven acquisition and exploitation track record;

Predictable, long-lived reserve base;

Diversified operations and operational control over approximately 70% of our current production; and

Experienced management team with a vested interest in our success.

Acquisition Activities

During the year ended December 31, 2008, we invested approximately $242.6 million, including non-cash asset retirement obligations, in 15 acquisitions of proved oil and natural gas properties. Based on reserve data prepared internally at the time of these acquisitions, we added a total of approximately 14.3 MMBoe of proved reserves at an average reserve acquisition cost of $15.18 per Boe, which excludes associated non-cash asset retirement obligations. Based on oil and natural gas prices of $41.00 per Bbl and $5.71 per MMBtu, respectively, as of December 31, 2008, these acquisitions added approximately 8.6 MMBoe of proved reserves at an average reserve acquisition cost of $25.25 per Boe.

Development Activities

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

As of December 31, 2008, we identified 94 gross (53.6 net) proved undeveloped drilling locations and 47 gross (19.9 net) re-completion and re-fracture stimulation projects. Excluding acquisitions, we expect to make capital expenditures of approximately $15 million during the year ending December 31, 2009, including drilling 12 gross (6.8 net) development wells and executing 21 gross (12.2 net) re-completions and re-fracture stimulations.

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Summary of Oil and Natural Gas Properties and Projects

As of December 31, 2008 we owned interests in producing oil and natural gas properties in 270 fields in the Permian Basin, Texas Panhandle, Oklahoma and several other states, operated 1,603 gross productive wells and owned non-operated interests in 2,247 gross productive wells. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2008. 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.

	As of December 31, 2008				
	Proved Reserves			Standardized Measure(a)	
	MMBoe	R/P(b)	% Oil and NGLs	Amount(c) ($ in millions)	% of Total
Texas Panhandle Fields	7.4	13	67%	$ 39.3	16.7%
Spraberry	3.7	11	69	34.6	14.7
Denton	1.7	10	86	14.9	6.4
East Binger	2.2	7	79	14.6	6.2
Farmer	1.2	12	65	7.9	3.3
Lea	1.0	17	68	6.7	2.9
Langlie Mattix	0.9	17	86	6.6	2.8
Total Top 7 fields	18.0	11	72%	$ 124.6	53.0%
All others	12.8	8	63	110.4	47.0
Total	30.8	10	68%	$ 235.0	100.0%

(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 prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provisions for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions.

(b) Reserves as of December 31, 2008 divided by annualized fourth quarter of 2008 production volumes.

(c) 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.

Oil and Natural Gas Data

The following table sets forth a summary of information related to our estimated net proved reserves as of the dates indicated based on reserve reports prepared by LaRoche Petroleum Consultants, Ltd. The estimates of net proved reserves have not been filed with or included in reports to any federal authority or

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agency. Standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31,		
	2008	2007	2006
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	16.6	19.6	13.4
Natural Gas Liquids (MMBbls)	4.3	4.0	
Natural Gas (Bcf)	59.3	50.9	32.5
Total (MMBoe)	30.8	32.1	18.8
Proved developed reserves (MMBoe)	28.0	29.0	15.8
Proved undeveloped reserves (MMBoe)	2.8	3.1	3.0
Proved developed reserves as a percentage of total proved reserves	91%	90%	84%
Standardized measure (in millions)	$ 235.0	$ 690.5	$ 240.6
Oil and Natural Gas Prices(a):			
Oil NYMEX WTI per Bbl	$ 41.00	$ 92.50	$ 57.75
Natural gas NYMEX Henry Hub per MMBtu	$ 5.71	$ 6.80	$ 5.64

(a) Oil and natural gas prices as of each date are based on NYMEX physical spot prices per Bbl of oil and per MMBtu of natural gas at such date, with these representative prices adjusted by property to arrive at the appropriate net sales price. These prices correlate to the NYMEX West Texas Intermediate near-month futures prices of $44.60, $95.98 and $61.05 per Bbl as of December 31, 2008, 2007 and 2006, respectively, and the NYMEX Henry Hub near-month futures prices of $5.62, $7.48 and $6.30 per MMBtu as of December 31, 2008, 2007 and 2006, respectively.

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 from our Annual Report on Form 10-K for the year ended December 31, 2008 incorporated by reference herein. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Standardized measure amounts shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Recent Developments

Second Quarter Cash Distribution

On August 14, 2009, we paid a cash distribution attributable to the second quarter of 2009 of $0.52 per unit to unitholders of record at the close of business on August 3, 2009. This quarterly distribution represents an annualized distribution of $2.08 per unit and maintains the distribution amount paid with respect to the prior four quarters.

Second Quarter Financial Results

Second Quarter of 2009 Compared to First Quarter of 2009. In the second quarter of 2009, Adjusted EBITDA increased 29% to $32.0 million from $24.8 million in the first quarter of 2009 due to the impact of increased commodity prices. Distributable cash flow increased to $24.7 million from $14.9 million.

We incurred a net loss for the second quarter of 2009 of $57.0 million, which was impacted by unrealized losses on commodity derivatives of approximately $75.8 million due to increases in oil and natural gas prices from the end of the first quarter as well as depletion, depreciation and amortization of $13.5 million. In the first quarter of 2009, we reported net income of $3.5 million, which included $0.5 million of unrealized gains on commodity derivatives and depletion, depreciation and amortization of $16.6 million.

Oil, NGLs and natural gas sales were $31.9 million, a 38% increase from $23.1 million in the first quarter due to the increase in commodity prices, which more than offset slightly lower production volumes. Production in the second quarter of 2009 decreased 2% to 8,154 Boe per day from 8,322 Boe per day in the first quarter of 2009 as a result of the reduction in development capital expenditures in the first half of 2009 compared to the second half of 2008 along with downtime related to third party gas plant maintenance in the Texas Panhandle.

In the second quarter of 2009, combined realized prices averaged $42.93 per Boe, up 39% from $30.79 per Boe in the first quarter of 2009 excluding the impact of commodity derivatives. Oil prices averaged $55.79 per barrel in the second quarter of 2009 compared to $35.79 per barrel in the first quarter of 2009, while natural gas prices increased marginally to $3.79 per MMBtu from $3.62 per MMBtu for the same period.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008. For the first half of 2009, Adjusted EBITDA was $56.8 million as compared to $58.6 million in the first half of 2008. The 3% decrease was primarily due to the decline in oil and natural gas sales revenues, offset by higher produced volumes and higher commodity derivatives settlements, which were $35.6 million compared to a $21.9 million loss in the first half of 2008 due to the decline in commodity prices year over year. As compared to the first half of 2008, distributable cash flow decreased 17% to $39.6 million from $47.5 million.

We incurred a net loss of $53.5 million for the first half of 2009, which was impacted by unrealized losses on commodity derivatives of approximately $75.3 million due to increases in oil and natural gas prices from the end of 2008 as well as depletion, depreciation and amortization of $30.2 million. In the first half of 2008 we reported a net loss of $196.9 million, which included unrealized losses on commodity derivatives of approximately $235.4 million and depletion, depreciation and amortization of $20.1 million.

For the six months ended June 30, 2009, production increased 16% to 8,238 Boe per day from 7,088 Boe per day for the six months ended June 30, 2008, as a result of acquisitions and development capital expenditures in 2008. Oil, NGL and natural gas sales were $54.9 million, a 52% decline from the $115.4 million realized during the first half of 2008 due to lower commodity prices in the period, partially offset by higher production volumes.

Combined realized prices averaged $36.83 per Boe, down 59% from $89.45 per Boe. Oil prices averaged $45.58 per barrel in the first half of 2009 compared to $109.02 per barrel in the first half of 2008, while natural gas prices declined to $3.71 per MMBtu from $9.85 per MMBtu.

Non-GAAP Financial Measures

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 or any other GAAP measure of liquidity or financial performance.

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Adjusted EBITDA is defined in our 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;
- Unit-based compensation expense related to LTIP unit awards accounted for under the equity or liability methods;
- Unrealized (gain) loss on oil and natural gas derivatives; and
- Equity in (income) loss of partnerships.

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.

Adjusted EBITDA and Distributable Cash Flow are presented as management believes they provide additional information and metrics relative to the performance of our business, such as the cash distributions we expect to pay to our unitholders, as well as our ability to meet our debt covenant compliance tests. Management believes that these financial measures indicate to investors whether or not cash flow is being generated at a level that can sustain or support an increase in our quarterly distribution rates. 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 companies may not calculate Adjusted EBITDA in the same manner.

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The following table presents a reconciliation of our consolidated net income (loss) to Adjusted EBITDA and Distributable Cash Flow:

	Three Months Ended		Six Months Ended	
	June 30, 2009	March 31, 2009	June 30, 2009	June 30, 2008
	($ in thousands)			
Net income (loss)	$ (56,992)	$ 3,489	$ (53,503)	$ (196,881)
Plus:				
Interest expense (income)	(1,761)	4,259	2,498	2,966
Income taxes	160	111	270	507
Depletion, depreciation, amortization and accretion	13,549	16,621	30,170	20,140
Impairment of long-lived assets	452	1,156	1,608	108
(Gain) loss on disposal of assets		(60)	(60)	(4,942)
Equity in (income) loss of partnership		2	3	(87)
Unit-based compensation expense	817	(281)	536	1,477
Unrealized (gain) loss on oil and natural gas derivatives	75,827	(526)	75,300	235,352
Adjusted EBITDA	$ 32,052	$ 24,771	$ 56,822	$ 58,640
Less:				
Cash interest expense	4,655	4,955	9,610	3,786
Cash settlements of LTIP unit awards	59	176	235	34
Development capital expenditures	2,647	4,769	7,416	7,364
Distributable Cash Flow	$ 24,691	$ 14,871	$ 39,561	$ 47,456

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Our Ownership and Organizational Structure

The chart below depicts our organization and ownership structure as of the date of this prospectus supplement before giving effect to this offering.

Ownership of Legacy Reserves LP

Public Unitholders	60.98%
Founding Investors, Directors and	