LEGACY RESERVES LP
Form 10-Q
May 08, 2009

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

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2009

or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-33249

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

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

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

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.

x Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

£ Yes £ No

Indicate by check mark 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.

Large accelerated filer o Accelerated filer x

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

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

31,074,339 units representing limited partner interests in the registrant were outstanding as of May 7, 2009.

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GLOSSARY OF TERMS

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

Bcf. Billion cubic feet.

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

Boe/d. Barrels of oil equivalent per day.

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

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

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

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

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

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

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

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

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

Mcf. One thousand cubic feet.

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

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMGal. One million gallons of natural gas liquids or other liquid hydrocarbons.

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

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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

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

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

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

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

Proved undeveloped reserves or PUDs. Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

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

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

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

Reserve replacement cost. An amount per Boe equal to the sum of costs incurred relating to oil and natural gas property acquisition, exploitation, development and exploration activities (as reflected in our year-end financial statements for the relevant year) divided by the sum of all additions and revisions to estimated proved reserves, including reserve purchases. The calculation of reserve additions for each year is based upon the reserve report of our independent engineers. Management uses reserve replacement cost to compare our company to others in terms of our historical ability to increase our reserve base in an economic manner. However, past performance does not necessarily reflect future reserve replacement cost performance. For example, increases in oil and natural gas prices in recent years have increased the economic life of reserves adding additional reserves with no required capital expenditures. On the other hand, increases in oil and natural gas prices have increased the cost of reserve purchases and reserves added through development. 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 prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provisions for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions.

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

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

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

Part I – FINANCIAL INFORMATION

Item 1. Financial Statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	March 31, 2009	December 31, 2008
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 3,034	$ 2,500
Accounts receivable, net:		
Oil and natural gas	10,738	12,198
Joint interest owners	7,669	7,265
Other (Note 4)	41	60
Fair value of derivatives (Notes 6 and 7)	56,279	54,820
Prepaid expenses and other current assets	4,523	4,094
Total current assets	82,284	80,937
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, at cost, using the successful efforts method of accounting:	826,323	821,786
Unproved properties	78	78
Accumulated depletion, depreciation and amortization	(225,029)	(208,832)
	601,372	613,032
Other property and equipment, net of accumulated depreciaton and amortization of $928 and $765, respectively	1,742	1,851
Operating rights, net of amortization of $1,566 and $1,429, respectively	5,451	5,588
Fair value of derivatives (Notes 6 and 7)	79,151	80,085
Other assets, net of amortization of $1,394 and $1,139, respectively	5,795	1,558
Investment in equity method investee	14	21
Total assets	$ 775,809	$ 783,072

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

LIABILITIES AND UNITHOLDERS' EQUITY

	March 31, 2009	December 31, 2008
	(In thousands)	
Current liabilities:		
Accounts payable	$ 1,671	$ 5,950
Accrued oil and natural gas liabilities	11,147	17,200
Fair value of derivatives (Notes 6 and 7)	5,006	1,691
Asset retirement obligation (Note 8)	29,210	25,889
Other (Note 10)	2,622	6,276
Total current liabilities	49,656	57,006
Long-term debt (Note 2)	300,000	282,000
Asset retirement obligation (Note 8)	51,210	54,535
Fair value of derivatives (Notes 6 and 7)	6,819	8,768
Other long-term liabilites	90	130
Total liabilities	407,775	402,439
Commitments and contingencies (Note 5)		
Unitholders' equity:		
Limited partners' equity - 31,069,339 and 31,049,299 units issued and outstanding at March 31, 2009 and December 31 2008, respectively	367,917	380,509
General partner's equity (approximately 0.1%)	117	124
Total unitholders' equity	368,034	380,633
Total liabilities and unitholders' equity	$ 775,809	$ 783,072

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$ 16,465	$ 36,049
Natural gas liquids sales (NGL)	2,069	3,502
Natural gas sales	4,525	9,236
Total revenues	23,059	48,787
Expenses:		
Oil and natural gas production	12,002	9,528
Production and other taxes	1,353	2,469
General and administrative	3,368	3,018
Depletion, depreciation, amortization and accretion	16,621	9,617
Impairment of long-lived assets	1,156	104
Loss on disposal of assets	208	48
Total expenses	34,708	24,784
Operating income (loss)	(11,649)	24,003
Other income (expense):		
Interest income	1	55
Interest expense (Notes 2, 6 and 7)	(4,259)	(4,178)
Equity in income (loss) of partnerships	(2)	42
Realized and unrealized gain (loss) on oil, NGL and natural gas swaps and oil collar (Notes 6 and 7)	19,505	(40,793)
Other	4	(16)
Income (loss) before income taxes	3,600	(20,887)
Income taxes	(111)	(210)
Net income (loss)	$ 3,489	$ (21,097)
Net income (loss) per unit - basic and diluted (Note 9)	$ 0.11	$ (0.71)
Weighted average number of units used in computing net income per unit -		
basic	31,053	29,674
diluted	31,067	29,674

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE THREE MONTHS ENDED MARCH 31, 2009
(UNAUDITED)

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders' Equity
		(In thousands)		
Balance, December 31, 2008	31,049	$ 380,509	$ 124	$ 380,633
Compensation expense on restricted unit awards issued to employees	-	71	-	71
Vesting of restricted units	20	-	-	-
Distributions to unitholders, $0.52 per unit	-	(16,149)	(10)	(16,159)
Net income	-	3,486	3	3,489
Balance, March 31, 2009	31,069	$ 367,917	$ 117	$ 368,034

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Three Months Ended March 31, 2009	2008
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 3,489	$ (21,097)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	16,621	9,617
Amortization of debt issuance costs	255	90
Impairment of long-lived assets	1,156	104
(Gain) loss on derivatives	(18,139)	42,937
Equity in (income) loss of partnership	2	(42)
Unit-based compensation	(457)	138
Loss on disposal of assets	208	48
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, oil and natural gas	1,460	(3,188)
(Increase) decrease in accounts receivable, joint interest owners	(404)	1,137
(Increase) decrease in accounts receivable, other	19	(15)
Increase in other current assets	(429)	(445)
Decrease in accounts payable	(4,279)	(742)
Increase (decrease) in accrued oil and natural gas liabilities	(6,053)	1,043
Decrease in other liabilities	(4,101)	(321)
Total adjustments	(14,141)	50,361
Net cash provided by (used in) operating activities	(10,652)	29,264
Cash flows from investing activities:		
Investment in oil and natural gas properties	(5,143)	(32,583)
Increase in deposit on pending acquisition	-	(3,066)
Proceeds from sale of assets	51	-
Investment in other equipment	(55)	(188)
Net cash settlements on oil and natural gas swaps	18,979	(6,767)
Investment in equity method investee	9	32
Net cash provided by (used in) investing activities	13,841	(42,572)
Cash flows from financing activities:		
Proceeds from long-term debt	21,000	40,000
Payments of long-term debt	(3,000)	(14,000)
Payments of debt issuance costs	(4,496)	-
Costs from issuance of units, net	-	(5)
Distributions to unitholders	(16,159)	(13,372)
Net cash provided by (used in) financing activities	(2,655)	12,623
Net increase (decrease) in cash and cash equivalents	534	(685)
Cash and cash equivalents, beginning of period	2,500	9,604
Cash and cash equivalents, end of period	$ 3,034	$ 8,919
Non-Cash Investing and Financing Activities:		

Asset retirement obligation costs and liabilities	$	-	$	502

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

(1) Summary of Significant Accounting Policies

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

Legacy Reserves LP and its affiliated entities are referred to as Legacy, LRLP or the Partnership in these financial statements.

Certain information and footnote disclosures normally included in the financial statements prepared in accordance with generally accepted accounting principles in the United States ("GAAP") have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission. These condensed consolidated financial statements should be read in connection with the consolidated financial statements and notes thereto included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2008.

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 owns less than a 0.1% general partner interest in LRLP.

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

• Right to receive, within 45 days after the end of each quarter, distributions of available cash, if distributions are declared.

• No limited partner shall have any management power over LRLP's 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, provided that a unit majority has elected a successor general partner.

• 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 and the Mid-continent region. Legacy has acquired oil and natural gas producing properties and undrilled leaseholds.

The accompanying condensed consolidated financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred. These condensed consolidated financial statements as of March 31, 2009 and for the three months ended March 31, 2009 and 2008 are unaudited. In the opinion of management, such financial statements include the adjustments and accruals which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results for a full year. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted in these financial statements for and as of the three months ended March 31, 2009 and 2008.

(b) Recently Issued Accounting Pronouncements

In February 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position No. 157-2 ("FSP FAS 157-2"). FSP FAS 157-2 deferred the effective date of Statement of Financial Accounting Standards No. 157 ("SFAS 157") for nonfinancial assets and liabilities to fiscal years beginning after November 15, 2008. Legacy adopted FSP FAS 157-2 effective January 1, 2009 and the adoption did not have a significant effect on Legacy's consolidated results of operations, financial position or cash flows. See Note 6 for other disclosures required by SFAS 157 and FSP FAS 157-2.

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

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

In March, 2008, the FASB issued Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities (“SFAS 161”). SFAS 161 amends and expands the disclosure requirements of FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities (“SFAS 133”). SFAS 161 requires disclosures related to objectives and strategies for using derivatives; the fair-value amounts of, and gains and losses on, derivative instruments; and credit-risk-related contingent features in derivative agreements. This statement is effective as of the beginning of an entity’s fiscal year beginning after December 15, 2008, which will be the Partnership’s fiscal year 2009. The effect on Legacy’s disclosures for derivative instruments as a result of the adoption of SFAS 161 in 2009 was not significant since the Partnership does not account for any of its derivatives as cash flow hedges.

During May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (“SFAS 162”). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements presented in conformity with GAAP. SFAS 162 is effective 60 days following the SEC’s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, “The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles.” Legacy does not expect that the adoption of SFAS 162 will have a significant impact on its financial statements.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (“FSP 03-6-1”), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS No. 128, Earnings per Share (“SFAS 128”). FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP 03-6-1 is not expected to have a material effect on Legacy’s net income per common unit calculations.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report the independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations. The new disclosure requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The Company is currently assessing the impact that adoption of this rule will have on its financial disclosures which will vary depending on changes in commodity prices.

In April 2009, the FASB issued FASB Staff Position ("FSP") SFAS No. 141(R)-1 Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies. This FSP amends and clarifies SFAS No. 141 (revised 2007), Business Combinations, to address application issues raised by preparers, auditors, and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP shall be effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Partnership has not made any acquisitions during the first quarter of 2009.

In April 2009, the FASB issued three FSP's to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP SFAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, provides guidelines for making fair value measurements more consistent with the principles presented in SFAS 157. FSP SFAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. These three FSP's are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. Legacy adopted the provisions of these FSP's for the period ending March 31, 2009. The adoption of these FSP's did not have a material impact on Legacy's financial position or results of operations.

(2) Credit Facility

In March of 2006, as an integral part of the formation of Legacy, Legacy entered into a credit agreement with a senior credit facility (the “Legacy Facility”) with oil and natural gas properties pledged as collateral for borrowings under the Legacy Facility. The initial terms of the Legacy Facility permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $300 million, increased to $500 million pursuant to the third amendment effective October 24, 2007. The initial borrowing base, set on March 16, 2006, was $130 million. The borrowing base, which had been redetermined pursuant to the fourth amendment to the credit agreement, was increased to $272 million as of April 24, 2008 and further increased to $320 million coincident with the closing of the COP III Acquisition, which closed on April 30, 2008. On October 6, 2008, the borrowing base was increased to $383.76 million pursuant to the fifth amendment and further increased to $410 million with the addition of two additional banks to the Legacy Facility. Under the Legacy Facility, as amended, interest on debt outstanding was charged based on Legacy’s selection of a LIBOR rate plus 1.50% to 2.125%, or the alternate base rate (“ABR”) which equaled the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.50%.

On March 27, 2009, Legacy entered into a new three-year secured revolving credit facility with BNP Paribas as administrative agent (the “New Credit Agreement”). Borrowings under the New Credit Agreement mature on April 1, 2012. The New Credit Agreement permits borrowings in the lesser amount of (i) the borrowing base, or (ii) $600 million. The borrowing base under the New Credit Agreement is $340 million as of March 31, 2009. The borrowing base is redetermined every six months and will be adjusted based upon changes in the fair market value of Legacy’s oil and natural gas assets. Under the New Credit Agreement, interest on debt outstanding is charged based on Legacy’s selection of a LIBOR rate plus 2.25% to 3.0%, or the alternate base rate (“ABR”) which equals 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%.

As of March 31, 2009, Legacy had outstanding borrowings of $300 million at a weighted-average interest rate of 3.52%. Legacy had approximately $40.0 million of availability remaining under the New Credit Agreement as of March 31, 2009. For the three-month period ended March 31, 2009, Legacy paid in cash $5.0 million of interest expense on the Legacy Facility and New Credit Agreement, which does not include the $4.3 million of upfront fees paid in cash related to the New Credit Agreement. These fees will be amortized over the life of the New Credit Agreement. The New Credit Agreement contains certain loan covenants requiring minimum financial ratio coverages, including the current ratio and EBITDA to interest expense. At March 31, 2009, Legacy was in compliance with all aspects of the New Credit Agreement.

Long-term debt consists of the following at March 31, 2009 and December 31, 2008:

	March 31, 2009	December 31, 2008
	(In thousands)	
Legacy Facility- due April 2012	$ 300,000	$ 282,000

(3) Acquisitions

COP III Acquisition

On April 30, 2008, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin and to a lesser degree in Oklahoma and Kansas from a third party for a net purchase price of $79.2 million. The purchase price was paid with the issuance of 1,345,291 newly issued units valued at $27.0 million and $52.2 million paid in cash (“COP III Acquisition”). The effective date of this purchase was January 1, 2008. The $79.2 million purchase price was allocated with $19.6 million recorded as lease and well equipment and $59.6 million as leasehold cost. Asset retirement obligations of $4.0 million were recorded in connection with this acquisition. The operating results from these COP III Acquisition properties have been included from their acquisition on April 30, 2008.

Reeves Unit Exchange

On May 2, 2008, Legacy entered into a non-monetary exchange with Devon Energy in which Legacy exchanged its 12.9% non-operated working interest in the Reeves Unit for a 60% interest in two operated properties. Legacy and Devon agreed upon a fair value of $7.7 million, prior to a net purchase price adjustment decrease of approximately $1.2 million, for both the Reeves Unit working interest and the acquired properties. Prior to the exchange, Legacy's basis in the Reeves Unit was $2.8 million. Due to the commercial substance of the transaction, the excess fair value of $3.7 million above the carrying value of the Reeves Unit was recorded as a gain on sale of discontinued operation for the year ended December 31, 2008. Due to immateriality, Legacy has not reflected the operating results of the Reeves Unit separately as a discontinued operation for any of the periods presented.

Pantwist Acquisition

On October 1, 2008, Legacy purchased all of the membership interests of Pantwist LLC (the "Pantwist Acquisition") from Cano Petroleum, Inc. for a net purchase price of $40.6 million. Pantwist owns certain oil and natural gas properties in Carson, Gray, Hutchison and Moore counties in the Texas Panhandle. The effective date of this purchase was July 1, 2008. The $40.6 million purchase price was allocated with $3.5 million recorded as lease and well equipment and $37.1 million of leasehold costs. Asset retirement obligations of $2.2 million were recorded in connection with this acquisition. The operations of the Pantwist properties have been included from their acquisition on October 1, 2008.

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the COP III and Pantwist Acquisitions had each occurred on January 1, 2008. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	Three Months Ended March 31, 2009	2008
	(In thousands)	
Revenues	$ 23,059	$ 56,220
Net income (loss)	$ 3,489	$ (18,757)
Income (loss) per unit - basic and diluted:	$ 0.11	$ (0.60)
Units used in computing income (loss) per unit:		
basic	31,053	31,020
diluted	31,067	31,020

(4) Related Party Transactions

Cary D. Brown, Legacy's Chairman and Chief Executive Officer, and Kyle A. McGraw, Legacy's Executive Vice President of Business Development and Land, own partnership interests which, in turn, own a combined non-controlling 4.16% interest as limited partners in the partnership which owns the building that Legacy occupies. Monthly rent is $14,808, without respect to property taxes and insurance. The lease expires in August 2011.

Legacy uses Lynch, Chappell and Alsup for legal services. Alan Brown, brother of Cary D. Brown, is a less than ten percent shareholder in this firm. Legacy paid legal fees to Lynch, Chappell and Alsup of $46,879 and $21,905 for the three months ended March 31, 2009 and 2008, respectively.

(5) Commitments and Contingencies

From time to time Legacy is a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, Legacy is not currently a party to any proceeding that it believes, if determined in a manner adverse to Legacy, could have a potential material adverse effect on its financial condition, results of operations or cash flows. Legacy believes the likelihood of such a future event to be remote.

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

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

On September 24, 2008, Legacy entered into a participation agreement with Black Oak Resources, LLC committing up to $20 million over three years to jointly invest in and develop oil and natural gas properties. Unless Black Oak Resources, LLC were to increase the $110 million of equity commitments initially committed or enter into a borrowing relationship, Legacy's obligations are expected to be in the range of $8 million over the next three years.

(6) Fair Value Measurements

As defined in SFAS 157, fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Legacy considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that Legacy values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps and interest rate swaps.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e. supported by little or no market activity). Legacy's valuation models are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 3 instruments primarily include derivative instruments, such as basis swaps and NGL derivative swaps. Although Legacy utilizes third party broker quotes to assess the reasonableness of its prices and valuation techniques, Legacy does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

As required by SFAS 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Legacy's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

The following table sets forth, by level within the fair value hierarchy, Legacy's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009:

	Fair Value Measurements at March 31, 2009 Using		
	Quoted Prices in	Significant Other	Significant

Description	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value as of March 31, 2009
	(In thousands)			
Oil, NGL and natural gas derivative swaps	$ -	$ 103,352	$ 17,020	$ 120,372
Oil collars	-	-	15,058	15,058
Interest rate swaps	-	(11,825)	-	(11,825)
Total	$ -	$ 91,527	$ 32,078	$ 123,605

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as level 3 in the fair value hierarchy:

	Significant Unobservable Inputs (Level 3) Three Months Ended March 31,	
	2009	2008
	(In thousands)	
Beginning balance	$ 28,985	$ (4,502)
Total gains or (losses)	6,707	(4,053)
Settlements	(3,614)	706
Transfers	-	-
Ending balance	$ 32,078	$ (7,849)
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of March 31, 2009 and 2008	$ 3,093	$ (3,347)

Fair Value on a Non-Recurring Basis

On January 1, 2009, Legacy adopted the provisions of SFAS 157 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis, which were delayed by FASB Staff Position No. FAS 157-2. As it relates to Legacy, this delayed adoption applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and natural gas property assessments; and the initial recognition of asset retirement obligations for which fair value is used.

This deferred adoption of SFAS 157 did not have a material impact on Legacy’s consolidated financial statements or its disclosures with respect to the initial recognition of asset retirement obligations during the three-month period ended March 31, 2009. These estimates are derived from historical costs as well as management’s expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Legacy has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of Legacy’s asset retirement obligation is presented in Note 8, in accordance with SFAS 143.

New assets measured at fair value during the three-month period ended March 31, 2009 include:

	Fair Value Measurements at March 31, 2009 Using			
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of March 31, 2009
	(In thousands)			
Assets:				
Proved oil and natural gas properties	$ -	$ -	$ 444	$ 444(a)
Total	$ -	$ -	$ 444	$ 444

(a) Legacy utilizes Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets ("SFAS 144"), to periodically review oil and natural gas properties for impairment when facts and circumstances indicate that their carrying value may not be recoverable. During the three-month period ended March 31, 2009, Legacy incurred impairment charges of $1.2 million as oil and natural gas properties with a net cost basis of $1.6 million were written down to their fair value of $0.4 million. The inputs used by management for the fair value measurements utilized in this review include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

(7) Derivative Financial Instruments

Commodity derivatives

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

All of these price risk management transactions are considered derivative instruments and accounted for in accordance with SFAS 133. These derivative instruments are intended to reduce Legacy's price risk and may be considered hedges for economic purposes but Legacy has chosen not to designate them as cash flow hedges for accounting purposes. Therefore, all derivative instruments are recorded on the balance sheet at fair value with changes in fair value being recorded in earnings for the period ended March 31, 2009.

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

For the three months ended March 31, 2009 and 2008, Legacy recognized realized and unrealized gains and losses related to its oil, NGL and natural gas derivatives. The impact on net loss from derivative activities was as follows:

	Three Months Ended March 31,	
	2009	2008
	(In thousands)	
Crude oil derivative contract settlements	$ 14,912	$ (6,578)
Natural gas liquid derivative contract settlements	470	(721)
Natural gas derivative contract settlements	3,597	532
Total commodity derivative contract settlements	18,979	(6,767)
Unrealized change in fair value - oil contracts	(5,600)	(25,276)
Unrealized change in fair value - natural gas liquid contracts	(645)	(12)
Unrealized change in fair value - natural gas contracts	6,771	(8,738)
Total unrealized change in fair value of commodity derivative contracts	526	(34,026)

Total realized and unrealized gains (losses) on commodity derivative contracts	$ 19,505	$ (40,793)

As of March 31, 2009, Legacy had the following NYMEX West Texas Intermediate crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
April - December 2009	1,117,920	$ 82.82	$61.05 - $140.00
2010	1,397,973	$ 82.37	$60.15 - $140.00
2011	1,155,712	$ 88.07	$67.33 - $140.00
2012	969,812	$ 81.28	$67.72 - $109.20
2013	240,000	$ 82.00	$82.00

On June 24, 2008, Legacy entered into a NYMEX West Texas Intermediate crude oil derivative collar contract that combines a put option or “floor” with a call option or “ceiling.” The following table summarizes the contract as of March 31, 2009:

Calendar Year	Volumes (Bbls)	Average Floor	Average Ceiling
April - December 2009	56,800	$ 120.00	$ 156.30
2010	71,800	$ 120.00	$ 156.30
2011	68,300	$ 120.00	$ 156.30
2012	65,100	$ 120.00	$ 156.30

As of March 31, 2009, Legacy had the following NYMEX Henry Hub, ANR-OK and Waha natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
April - December 2009	2,379,340	$ 7.94	$6.85 - $9.29
2010	2,840,859	$ 7.87	$6.85 - $9.73
2011	2,127,316	$ 8.01	$6.85 - $8.70
2012	1,579,736	$ 8.02	$6.85 - $8.70

As of March 31, 2009, Legacy had the following gas basis swaps in which it receives floating NYMEX prices less a fixed basis differential and pay prices on the floating Waha index, a natural gas hub in West Texas. The prices that Legacy receives for its natural gas sales in the Permian Basin follow Waha more closely than NYMEX:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per MMBtu
April - December 2009	990,000	($0.68)
2010	1,200,000	($0.57)

As of March 31, 2009, Legacy had the following gas basis swaps in which it receives floating NYMEX prices less a fixed basis differential and pay prices on the floating ANR-Oklahoma index, a natural gas hub in Oklahoma. The prices Legacy receives for its natural gas sales in the Texas Panhandle and Oklahoma follow ANR-Oklahoma more closely than NYMEX:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per MMBtu
April - December 2009	360,000	($1.09)

2010	480,000	($0.87)

As of March 31, 2009, Legacy had the following Mont Belvieu, Non-Tet OPIS natural gas liquids swaps paying floating natural gas liquids prices and receiving fixed prices for a portion of its future natural gas liquids production as indicated below:

Calendar Year	Volumes (Gal)	Average Price per Gal	Price Range per Gal
April - December 2009	1,699,110	$ 1.15	$1.15

Interest rate derivatives

Due to the volatility of interest rates, Legacy periodically enters into interest rate risk management transactions in the form of interest rate swaps for a portion of its outstanding debt balance. These transactions allow Legacy to reduce exposure to interest rate fluctuations. While the use of these arrangements limits Legacy's ability to benefit from decreases in interest rates, it also reduces Legacy's potential exposure to adverse interest rate movements. Legacy's arrangements, to the extent it enters into any, apply to only a portion of its outstanding debt balance, provide only partial protection against interest rate increases and limit Legacy's potential savings from future interest rate declines. None of these instruments are used for trading or speculative purposes.

On August 29, 2007, Legacy entered into LIBOR interest rate swaps beginning in October of 2007 and extending through November 2011. On January 29, 2009, Legacy revised the LIBOR interest rate swaps. The revised swap transaction has Legacy paying its counterparty fixed rates ranging from 4.09% to 4.11%, per annum, and receiving floating rates on a total notional amount of $54 million. The swaps are settled on a monthly basis, beginning in January of 2009 and ending in November of 2013.

On March 14, 2008, Legacy entered into a LIBOR interest rate swap beginning in April of 2008 and extending through April of 2011. On January 28, 2009, Legacy revised the LIBOR interest rate swap extending the term through April of 2013. The revised swap transaction has Legacy paying its counterparty a fixed rate of 2.65% per annum, and receiving floating rates on a notional amount of $60 million. The swap is settled on a monthly basis, beginning in April of 2009 and ending in April of 2013. Prior to April of 2009, the swap was settled on a quarterly basis.

On October 6, 2008, Legacy entered into two LIBOR interest rate swaps beginning in October of 2008 and extending through October 2011. In January of 2009, Legacy revised these LIBOR interest rate swaps extending the termination date through October of 2013. The revised swap transactions have Legacy paying its counterparties fixed rates ranging from 3.09% to 3.10%, per annum, and receiving floating rates on a total notional amount of $100 million. The revised swaps are settled on a monthly basis, beginning in January of 2009 and ending in October of 2013.

On December 16, 2008, Legacy entered into a LIBOR interest rate swap beginning in December of 2008 and extending through December 2013. The swap transaction has Legacy paying its counterparty a fixed rate of 2.295%, per annum, and receiving floating rates on a total notional amount of $50 million. The swap is settled on a quarterly basis, beginning in March of 2009 and ending in December of 2013.

Legacy accounts for these interest rate swaps pursuant to SFAS 133. This statement establishes accounting and reporting standards requiring that derivative instruments be recorded at fair market value and included in the balance sheet as assets or liabilities.

As the term of Legacy's interest rate swaps extends through December of 2013, a period that extends beyond the term of the Legacy Facility, which expires on April 1, 2012, Legacy did not specifically designate these derivatives as cash flow hedges, even though they reduce its exposure to changes in interest rates. Therefore, the mark-to-market of these instruments, which amounted to $1.4 million and $2.1 million for the three months ended March 31, 2009 and 2008, respectively, is recorded in current earnings as interest expense. The total impact on income expense from the mark-to-market and settlements was as follows:

	Three Months Ended March 31,	
	2009	2008
	(In thousands)	
Interest rate swap settlements	$ (37)	$ (40)
Unrealized change in fair value - interest rate swaps	1,366	2,145

Total increase to interest expense, net	$	1,329	$	2,105

The table below summarizes the interest rate swap position as of March 31, 2009.

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at March 31, 2009
		(Dollars in thousands)		
$ 29,000	4.0900%	10/16/2007	10/16/2013	$ (2,641)
$ 13,000	4.1100%	11/16/2007	11/16/2013	(1,207)
$ 12,000	4.1100%	11/28/2007	11/28/2013	(1,100)
$ 60,000	2.6500%	4/1/2008	4/1/2013	(1,765)
$ 50,000	3.1000%	10/10/2008	10/10/2013	(2,348)
$ 50,000	3.0900%	10/10/2008	10/10/2013	(2,360)
$ 50,000	2.2950%	12/18/2008	12/18/2013	(404)
Total Fair Market Value of interest rate derivatives				$ (11,825)

(8) Asset Retirement Obligation

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

The following table reflects the changes in the ARO during the three months ended March 31, 2009 and year ended December 31, 2008.

	March 31, 2009	December 31, 2008
	(In thousands)	
Asset retirement obligation - beginning of period	$ 80,424	$ 15,920
Liabilities incurred with properties acquired	-	25,023
Liabilities incurred with properties drilled	-	456
Liabilities settled during the period	(711)	(440)
Liabilities associated with properties sold	-	(304)
Current period accretion	707	1,396
Current period revisions to previous estimates	-	38,373
Asset retirement obligation - end of period	$ 80,420	$ 80,424

(9) Earnings (Loss) Per Unit

The following table sets forth the computation of basic and diluted net earnings (loss) per unit:

	Three Months Ended March 31, 2009	2008
	(In thousands)	
Income (loss) available to unitholders	$ 3,489	$ (21,097)
Weighted average number of units outstanding	31,053	29,674
Effect of dilutive securities:		
Restricted units	14	-
Weighted average units and potential units outstanding	31,067	29,674
Basic and diluted earnings (loss) per unit	$ 0.11	$ (0.71)

(10) Unit-Based Compensation

Long-Term Incentive Plan

Concurrent with the Legacy Formation on March 15, 2006, a Long-Term Incentive Plan for Legacy was created and Legacy adopted Statement of Financial Accounting Standards No. 123(R)-Share-Based Payment ("SFAS 123(R)"). Legacy adopted the Legacy Reserves LP Long-Term Incentive Plan ("LTIP") for its employees, consultants and directors, its affiliates and its general partner. The awards under the LTIP may include unit grants, restricted units, phantom units, unit options and unit appreciation rights. The LTIP permits the grant of awards covering an aggregate of 2,000,000 units. As of March 31, 2009, grants of awards net of forfeitures covering 794,916 units had been made, comprised of 624,550 unit options and unit appreciation rights awards, 65,116 restricted unit awards and 105,250 phantom unit awards. The LTIP is administered by the compensation committee of the board of directors of Legacy's general partner (the "Compensation Committee").

SFAS 123(R) requires companies to measure the cost of employee services in exchange for an award of equity instruments based on a grant-date fair value of the award (with limited exceptions), and that cost must generally be recognized over the vesting period of the award. Prior to April of 2007, Legacy utilized the equity method of accounting as described in SFAS 123(R) to recognize the cost associated with unit options. However, SFAS 123(R) stipulates that "if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if the entity usually settles in cash whenever an employee asks for cash settlement, the entity is settling a substantive liability rather than repurchasing an equity instrument."

The initial vesting of options occurred on March 15, 2007, with initial option exercises occurring in April 2007. At the time of the initial exercise, Legacy settled these exercises in cash and determined it was likely to do so for future option exercises. Consequently, in April 2007, Legacy began accounting for unit option grants by utilizing the liability method as described in SFAS 123(R). The liability method requires companies to measure the cost of the employee services in exchange for a cash award based on the fair value of the underlying security at the end of the period. Compensation cost is recognized based on the change in the liability between periods.

Unit Options and Unit Appreciation Rights

During the year ended December 31, 2008, Legacy issued 104,000 unit appreciation rights ("UARs") to employees which vest ratably over a three-year period and 108,450 UARs to employees which cliff-vest at the end of a three-year period. During the three-month period ended March 31, 2009, Legacy issued 4,500 UARs to employees which vest ratably over a three-year period. All UARs granted in 2008 and 2009 expire five years from the grant date and are exercisable when they vest.

For the three-month periods ended March 31, 2009 and 2008, Legacy recorded $441,065 and $45,043, respectively, of compensation income due to the change in liability from December 31, 2008 and 2007, respectively, based on its use of the Black-Scholes model to estimate the March 31, 2009 and 2008 fair value of these unit options and UARs. As of March 31, 2009, there was a total of $74,766 of unrecognized compensation costs related to the unexercised and non-vested portion of these unit options and UARs. At March 31, 2009, this cost was expected to be recognized over a weighted-average period of approximately 3.2 years. Compensation expense is based upon the fair value as of March 31, 2009 and is recognized as a percentage of the service period satisfied. Since Legacy has limited trading history, it has used an estimated volatility factor of approximately 66% based upon the historical trends of a representative group of publicly-traded companies in the energy industry and employed the Black-Scholes model to estimate the March 31, 2009 fair value to be realized as compensation cost based on the percentage of service period satisfied. In the absence of historical data, Legacy has assumed an estimated forfeiture rate of 5%. As required by SFAS 123(R), Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.08 per unit.

A summary of option and UAR activity for the three months ended March 31, 2009 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value	
Outstanding at January 1, 2009	591,682				
Granted	4,500	$ 10.20			
Exercised	-	$ -			
Forfeited	-	$ -			
Outstanding at March 31, 2009	596,182	$ 19.90	3.21	$ 1,540	(a)
Options and UARs exercisable at March 31, 2009	237,837	$ 18.59	2.34	$ -	(b)

(a) At March 31, 2009, the market value of the partnership's units was $9.13, a price which was less than the average exercise price of outstanding options and UARS of $19.90. At March 31, 2009, there were 2,000 units with an intrinsic value of $0.77 per unit.

(b) At March 31, 2009, there were no exercisable options or UARS with an intrinsic value due to the market value of the Partnership's units of $9.13, a price which is less than the average exercise price of $18.59 per unit for exercisable options and UARs.

The following table summarizes the status of Legacy's non-vested unit options and UARs since January 1, 2009:

	Non-Vested Options and UARs	
	Number of Units	Weighted-Average Fair Value
Non-vested at January 1, 2009	421,720	$ 1.75
Granted	4,500	10.20
Vested - Unexercised	(67,875)	17.83
Vested - Exercised	-	-
Forfeited	-	-
Non-vested at March 31, 2009	358,345	$ 20.83

Legacy has used a weighted-average risk-free interest rate of 1.4% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at March 31, 2009 whose term is consistent with the expected life of the unit options and UARs. Expected life represents the period of time that options and UARs are expected to be outstanding and is based on Legacy's best estimate. The following table represents the weighted-average assumptions used for the Black-Scholes option-pricing model.

	Three Months Ended March 31, 2009
Expected life (years)	5
Annual interest rate	1.4%
Annual distribution rate per unit	$ 2.08
Volatility	66%

Restricted and Phantom Units

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

On February 4, 2008, Legacy granted 2,750 phantom units to four employees which vest ratably over a three-year period, beginning at the date of grant. On May 1, 2008, Legacy granted 3,000 phantom units to an employee which vest ratably over a three-year period, beginning at the date of grant. On January 29, 2009, Legacy granted 4,500 phantom units to six employees which vest ratably over a three-year period, beginning at the date of grant. In conjunction with these grants, the employees are entitled to distribution equivalent rights ("DERs") for unvested units held at the date of dividend payment.

On August 20, 2007, the board of directors of Legacy's general partner, upon recommendation from the Compensation Committee, approved phantom unit awards of up to 175,000 units to five key executives of Legacy based on achievement of targeted annualized per unit distribution levels over a base amount of $1.64 per unit. These awards are to be determined annually based solely on the annualized level of per unit distributions for the fourth quarter of each calendar year and subsequently vest over a three-year period. There is a range of 0% to 100% of the distribution levels at which the performance condition may be met. For each quarter, management recommends to the board an appropriate level of per unit distribution based on available cash of Legacy. The level of distribution is set by the board subsequent to management's recommendation. Probable issuances for the purposes of calculating compensation expense associated therewith are determined based on management's determination of probable future distribution levels. Expense associated with probable vesting is recognized over the period from the date probable vesting is determined to the end of the three-year vesting period. On February 4, 2008, the Compensation Committee approved the award of 28,000 phantom units to Legacy's five executive officers. On January 29, 2009, the Compensation Committee approved the award of 49,000 phantom units to Legacy's five executive officers. In conjunction with these grants, the executive officers are entitled to DERs for unvested units held at the date of dividend payment. Compensation expense related to the phantom units and associated DERs was $89,288 and $85,767 for the three months ended March 31, 2009 and 2008, respectively.

On March 15, 2006, Legacy issued an aggregate of 52,616 restricted units to two employees. The restricted units awarded vest ratably over a three-year period, beginning on the date of grant. On May 5, 2006, Legacy issued 12,500 restricted units to an employee. The restricted units awarded vest ratably over a five-year period, beginning on March 31, 2007. Compensation expense related to restricted units was $71,085 and $85,164 for the three months ended March, 31, 2009 and 2008, respectively. As of March 31, 2009, there was a total of $84,533 of unrecognized compensation expense related to the non-vested portion of these restricted units. At March 31, 2009, this cost was expected to be recognized over a weighted-average period of 2.0 years. Pursuant to the provisions of SFAS 123(R), Legacy's issued units, as reflected in the accompanying consolidated balance sheet at March 31, 2009, do not include 5,000 units related to unvested restricted unit awards.

On March 5, 2008, Legacy issued 583 units, granted on January 23, 2008, to its newly elected non-employee director as part of his pro-rata annual compensation for serving on Legacy's board. The value of each unit was $21.20 at the time of grant. On August 29, 2008, Legacy issued 2,500 units, granted on August 26, 2008, to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $20.09 at the time of issuance.

(11) Subsequent Events

On April 3, 2009, Legacy's board of directors announced the receipt of a proposal from Apollo Management VII, LP ("Apollo Management") to acquire all of the outstanding units of Legacy Reserves LP at a cash purchase price of $14.00 per unit, subject to adjustment for any distributions paid to the Partnership's limited partners. The Conflicts Committee of the board of directors has retained the law firm of Richards, Layton & Finger, P.A. as its legal advisor and has retained the services of Tudor, Pickering, Holt & Co., an energy investment banking firm, as its financial advisor to evaluate the proposal by Apollo Management. The Conflicts Committee of the board of directors has not made any decision with respect to the proposal. There can be no assurance that any definitive offer will be made, any agreement will be executed, or that any transaction will be approved or consummated.

On April 23, 2009, Legacy's board of directors approved a distribution of $0.52 per unit payable on May 14, 2009 to unitholders of record on May 3, 2009.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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:

- the amount of oil and natural gas we produce;
- the level of capital expenditures;
- 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:
- our future operating results; and
- our business strategy, 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 Legacy's Annual Report on Form 10-K for the year ended December 31, 2008 and this Quarterly Report on Form 10-Q in Item 1A under "Risk Factors." The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly.

Overview

We were formed in October 2005. Upon completion of our private equity offering and as a result of the formation of Legacy 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 from the COP III Acquisition have been included from April 30, 2008 and the operating results from the Pantwist Acquisition have been included from October 1, 2008.

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 developing 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, our access to capital and the amount of our cash distributions.

Outlook: The current global economic environment has reduced the demand for oil and natural gas and resulted in a significant decrease of commodity prices. In addition, financial and credit markets have deteriorated, virtually shutting down access to public financial markets and significantly reducing the availability of credit. We cannot predict future commodity prices nor when or whether credit conditions will ease and financial markets will become available again. Based on the sustained decrease in commodity prices which began in the third and fourth quarters of 2008, we are experiencing a challenging 2009. A sustained period of reduced commodity prices will have an adverse effect on our operating income and cash flow in future periods resulting in decreased revenues and higher depletion rates, and as a result, will adversely impact our ability to pay cash distributions at current levels.

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

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 derivative transactions covering a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our capital investment programs and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact, if any, on any redetermination of 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.

Production and Operating Costs Reporting

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

Such costs include, but are not limited to, the cost of electricity to lift produced fluids, chemicals to treat wells, field personnel to monitor the wells, well repair expenses to restore production, well workover expenses intended to increase production, and ad valorem taxes. We incur and separately report severance taxes paid to the states 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 and are reported with production costs. 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.

Operating Data

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$ 16,465	$ 36,049
Natural gas liquid sales	2,069	3,502
Natural gas sales	4,525	9,236
Total revenue	$ 23,059	$ 48,787
Expenses:		
Oil and natural gas production	$ 10,537	$ 8,996
Ad valorem taxes	$ 1,465	$ 532
Total oil and natural gas production	$ 12,002	$ 9,528
Production and other taxes	$ 1,353	$ 2,469
General and administrative	$ 3,368	$ 3,018
Depletion, depreciation, amortization and accretion	$ 16,621	$ 9,617
Realized swap settlements		
Realized gain (loss) on oil swaps	$ 14,912	$ (6,578)
Realized gain (loss) on natural gas liquid swaps	$ 470	$ (721)
Realized gain on natural gas swaps	$ 3,597	$ 532
Production:		
Oil - barrels	460	379
Natural gas liquids - gallons	3,388	2,721
Natural gas - Mcf	1,249	1,058
Total (MBoe)	749	620
Average daily production (Boe/d)	8,322	6,813
Average sales price per unit (excluding swaps):		
Oil price per barrel	$ 35.79	$ 95.12
Natural gas liquid price per gallon	$ 0.61	$ 1.29
Natural gas price per Mcf	$ 3.62	$ 8.73
Combined (per Boe)	$ 30.79	$ 78.69
Average sales price per unit (including realized swap gains/losses):		
Oil price per barrel	$ 68.21	$ 77.76
Natural gas liquid price per gallon	$ 0.75	$ 1.02
Natural gas price per Mcf	$ 6.50	$ 9.23
Combined (per Boe)	$ 56.13	$ 67.77
NYMEX oil index prices per barrel:		
Beginning of Period	$ 44.60	$ 95.98
End of Period	$ 49.66	$ 101.58

NYMEX gas index prices per Mcf:				
Beginning of Period	$	5.62	$	7.48
End of Period	$	3.78	$	10.10
Average unit costs per Boe:				
Oil and natural gas production	$	14.07	$	14.51
Ad valorem taxes	$	1.96	$	0.86
Production and other taxes	$	1.81	$	3.98
General and administrative	$	4.50	$	4.87
Depletion, depreciation, amortization and accretion	$	22.19	$	15.51

Results of Operations

Three-Month Period Ended March 31, 2009 Compared to Three-Month Period Ended March 31, 2008

Legacy's revenues from the sale of oil were $16.5 million and $36.0 million for the three-month periods ended March 31, 2009 and 2008, respectively. Legacy's revenues from the sale of NGLs were $2.1 million and $3.5 for the three-month periods ended March 31, 2009 and 2008, respectively. Legacy's revenues from the sale of natural gas were $4.5 million and $9.2 million for the three-month periods ended March 31, 2009 and 2008, respectively. The $19.5 million decrease in oil revenues reflects the decrease in average realized price of $59.33 per Bbl (62%). In addition to the decrease in NYMEX WTI oil prices, our realized oil revenues were impacted by widening price differentials to NYMEX WTI. Our realized differentials during the three-month period ended March 31, 2009 were $7.42 per barrel less than NYMEX WTI compared to $2.87 less than NYMEX WTI during the three-month period ended March 31, 2008. These price declines were partially offset by an increase in oil production of 81 MBbls (21%) due primarily to Legacy's purchase of the oil and natural gas properties in the COP III and Pantwist Acquisitions. The $1.4 million decrease in proceeds from NGL sales reflects the decrease in realized NGL price of $0.68 per gallon (53%) partially offset by an increase in NGL production of approximately 667,000 gallons (25%) due primarily to Legacy's purchase of oil and natural gas properties in the COP III and Pantwist Acquisitions. The $4.7 million decrease in natural gas revenues reflects the decrease in average realized price per Mcf of $5.11 per Mcf (59%) partially offset by an increase in natural gas production of approximately 191 MMcf (18%) due primarily to Legacy's purchase of oil and natural gas properties acquired in the COP III and Pantwist Acquisitions.

For the three-month period ended March 31, 2009, Legacy recorded $19.5 million of net gains on oil, NGL and natural gas swaps comprised of realized gains of $19.0 million from net cash settlements of oil, NGL and natural gas swap contracts and net unrealized gains of $0.5 million. Legacy had unrealized net losses from oil swaps because the price of oil increased during the three-month period ended March 31, 2009. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close increased from $44.60 per Bbl at December 31, 2008 to $49.66 per Bbl at March 31, 2009, a price which is less than the average contract prices of Legacy's outstanding oil swap contracts, but greater than the price at December 31, 2008, resulting in a reduction of unrealized net gain attributable to Legacy's outstanding oil swap contracts. Due to the increase in oil prices during the quarter, the differential between Legacy's fixed price oil swaps and NYMEX decreased, resulting in losses for the quarter. Legacy had unrealized net losses from NGL swaps because NGL prices increased during the three-month period ended March 31, 2009. Legacy had unrealized net gains from natural gas swaps because the NYMEX natural gas prices declined during the three-month period ended March 31, 2009. As a point of reference, the NYMEX price for natural gas for the near-month close decreased from $5.62 per MMBtu at December 31, 2008 to $3.78 per MMBtu at March 31, 2009, a price which is less than the average contract prices of Legacy's outstanding natural gas swap contracts, but less than the price at December 31, 2008, resulting in an increase of unrealized net gain attributable to Legacy's outstanding natural gas swap contracts. For the three-month period ended March 31, 2008, Legacy recorded $40.8 million of net losses on oil, NGL and natural gas swaps comprised of realized losses of $6.8 million from net cash settlements of oil, NGL and natural gas swap contracts and a net unrealized loss of $25.3 million on oil swap contracts, due to the increase in oil prices during the quarter which increased the differential between the NYMEX oil index price and our fixed price oil swaps, a net unrealized loss of $0.01 million on NGL swap contracts and a net unrealized loss of $8.7 million on natural gas swap contracts, due to the increase in natural gas prices during the period. 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 $10.5 million ($14.07 per Boe) for the three-month period ended March 31, 2009, from $9.0 million ($14.51 per Boe) for the three-month period ended March 31, 2008. Production expenses increased primarily because of $1.7 million of production expenses related to the COP III and Pantwist Acquisitions. Legacy's ad valorem taxes increased to $1.5 million ($1.96 per Boe) for the three-month period ended March 31, 2009, from $0.5 million ($0.86 per Boe) for the three-month period ended

March 31, 2008 primarily because of increased well counts and periods of ownership from 2008 acquisition activity.

Legacy's production and other taxes were $1.4 million and $2.5 million for the three-month periods ended March 31, 2009 and 2008, respectively. Production and other taxes decreased primarily because of the decrease in realized prices. As production and other taxes are a function of price and volume, the decrease is consistent with the decrease in realized prices.

Legacy's general and administrative expenses were $3.4 million and $3.0 million for the three-month periods ended March 31, 2009 and 2008, respectively. General and administrative expenses increased approximately $0.4 million between the three-month periods ended March 31, 2009 and 2008 primarily due to increases in payroll related to an increased headcount due to growth in our asset base.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $16.6 million and $9.6 million for the three-month periods ended March 31, 2009 and 2008, respectively. DD&A increased partially because of $2.1 million of DD&A related to the COP III and Pantwist Acquisitions. In addition, the increase in DD&A expense per Boe, from $15.51 to $22.19 for the three-month periods ended March 31, 2008 and 2009, respectively, reflects the decreased commodity prices combined with the higher cost basis of the producing oil and natural gas properties acquired in recent acquisitions.

Impairment expense was $1.1 million and $0.1 million for the three-month periods ended March 31, 2009 and 2008, respectively. In the period ended March 31, 2009, Legacy recognized impairment expense in five separate producing fields, due primarily to lower natural gas prices, rising production costs and, in the case of one field, performance. The impairment expense for the period ended March 31, 2008, involved one producing field due primarily to costs incurred in the period during which the estimated production revenues did not exceed the costs.

Legacy recorded interest expense of $4.3 million and $4.2 million for the three-month periods ended March 31, 2009 and 2008, respectively, reflecting higher average borrowings in the period ended March 31, 2009 partially offset by lower average interest rates.

Capital Resources and Liquidity

Legacy's primary sources of capital and liquidity have been bank borrowings, cash flow from operations, its private offering in March 2006, the IPO in January 2007 and its private offering in November 2007. To date, Legacy's primary use of capital has been for acquisitions, repayment of bank borrowings and development of oil and natural gas properties.

We continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in maintaining and growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and developing additional reserves. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our credit facility, if available, or obtain additional debt or equity financing. While we actively review acquisition opportunities on an ongoing basis, current overall economic conditions and the lack of debt and equity financing at economically attractive terms severely limit our ability to execute any significant acquisition transactions. Further, our credit facility imposes certain restrictions on our ability to obtain additional debt financing. Based upon current oil and natural gas price expectations for the year ending December 31, 2009, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our credit facility will provide us sufficient working capital to meet our currently planned capital expenditures and future cash distributions at levels to be determined based on cash available for distribution, any remaining borrowing capacity for cash distributions under our credit facility, requirements to repay debt, and any other factors the board of directors of our general partner may consider.

To reduce debt, the board of directors of our general partner on April 23, 2009 approved a reduction in our 2009 capital expenditure budget to $10.7 million from the $20 million budget approved in February 2009. Also on April 23, 2009, the board of directors approved a cash distribution of $0.52 per unit with respect to the first quarter of 2009, or $16.16 million in the aggregate. With respect to any future distributions, we continue to review our distribution policy to maintain liquidity given the volatile commodity price and capital markets environment. In each of the last three quarters, we distributed more cash than we generated. This is not a sustainable scenario; thus, a reduction in distribution levels will likely be necessary in the coming quarters unless a significant improvement in oil and natural gas prices occurs.

Further, given the semi-annual borrowing base redeterminations and potentially lower bank price forecasts, which are determined by our lenders based on their commodity price expectations, a reduction in our borrowing base may occur at the time of the scheduled redetermination in October 2009 or earlier, at the request of the lenders. Should our borrowing base be decreased below the amount of debt then outstanding, which as of May 7, 2009 was $300 million, we would be required to pay down our debt to a level below the newly reduced borrowing base. As noted above, we have already reduced our capital expenditure budget for fiscal year 2009 to $10.7 million and thus would need to reduce our future distributions to prospectively lower our debt balance. Please read "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Legacy's net cash provided by (used in) operating activities was $(10.7) million and $29.3 million for the three-month periods ended March 31, 2009 and 2008, respectively, with the 2009 period being unfavorably impacted by lower commodity prices.

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

Investing Activities

Legacy's cash capital expenditures were $5.1 million for the three-month period ended March 31, 2009. The total includes $4.8 million of development projects and $0.3 million in purchase price adjustments on previous acquisitions. Legacy's cash capital expenditures were $32.6 million for the three-month period ended March 31, 2008. The total includes $29.6 million for the acquisition of oil and natural gas properties in small acquisitions and $3.0 million of development projects.

We currently anticipate that our capital expenditure budget, which predominantly consists of drilling, recompletion and re-fracture stimulation projects will be $10.7 million for the year ending December 31, 2009. Our remaining borrowing capacity under our revolving credit facility is $40.0 million as of May 7, 2009. 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. 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. Based upon current oil and natural gas price expectations for the year ending December 31, 2009, we anticipate that we will have sufficient sources of working capital, including our cash flow from operations and available borrowing capacity under our credit facility, to meet our cash obligations including our planned capital expenditures of $10.7 million. Future cash distributions will be at levels to be determined based on cash available for distribution, any remaining borrowing capacity for cash distributions under our credit facility, requirements to repay debt and any other factors the board of directors of our general partner may consider. 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.

We enter into oil, NGL and natural gas derivatives to reduce the impact of oil, NGL and natural gas price volatility on our operations. Currently, we use swaps and collars to offset price volatility on NYMEX oil, NGL and natural gas prices, which do not include the additional net discount that we typically experience in the Permian Basin. At March 31, 2009, we had in place oil, NGL and natural gas swaps covering significant portions of our estimated 2008 through 2013 oil, NGL and natural gas production. As of May 7, 2009, we have swap contracts covering approximately 74.9% of our remaining expected oil, natural gas liquid and natural gas production for 2009. As of May 7, 2009, we also have swap and collar contracts covering approximately 54.0% of our currently expected oil and natural gas production for 2010 through 2013 from existing estimated total proved reserves.

By reducing the cash flow effects of price volatility 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 from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. In addition, these counterparties are members of our revolving credit facility, which allows us to avoid margin calls. However, due to the recent severe disruptions in the financial markets, we can no longer predict whether any counterparty will meet its obligations under our derivative contracts. Due to this uncertainty, we routinely monitor the creditworthiness of our counterparties.

The following tables summarize, for the periods indicated, our oil and natural gas swaps currently in place as of May 7, 2009, through December 31, 2013. We use swaps and collars as our mechanism for offsetting the cash flow effects of changes in commodity prices whereby we pay the counterparty floating prices and receive fixed prices from the counterparty, which serves to reduce the effects on cash flow of 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 Henry Hub, West Texas Waha and ANR-Oklahoma 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.

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
April - December 2009	1,117,920	$ 82.82	$61.05 - $140.00
2010	1,397,973	$ 82.37	$60.15 - $140.00
2011	1,155,712	$ 88.07	$67.33 - $140.00

2012	969,812	$ 81.28	$67.72 - $109.20
2013	240,000	$ 82.00	$82.00

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
April - December 2009	2,379,340	$ 7.94	$6.85 - $9.29
2010	2,840,859	$ 7.87	$6.85 - $9.73
2011	2,127,316	$ 8.01	$6.85 - $8.70
2012	1,579,736	$ 8.02	$6.85 - $8.70

In July 2006, we entered into natural gas basis swaps to receive floating NYMEX natural gas prices less a fixed basis differential and pay prices based on the floating Waha index, a natural gas hub in West Texas. The prices that we receive for our natural gas sales follow Waha more closely than NYMEX. The basis swaps thereby provide a better match between our natural gas sales and the settlement payments on our natural gas swaps. The following table summarizes, for the periods indicated, our NYMEX-Waha basis swaps currently in place as of May 7, 2009, through December 31, 2010:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per MMBtu
April - December 2009	990,000	($0.68)
2010	1,200,000	($0.57)

In December of 2008, we entered into basis swaps to receive floating NYMEX Henry Hub natural gas prices less a fixed basis differential and pay prices based on the floating ANR-Oklahoma index, a natural gas hub in Oklahoma. The prices that we receive for our Texas Panhandle and Oklahoma gas sales follow ANR-Oklahoma more closely than NYMEX. The following table summarizes, for the periods indicated, our NYMEX-ANR-Oklahoma basis swaps in place as of May 7, 2009 through December 31, 2010:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per MMBtu
April - December 2009	360,000	($1.09)
2010	480,000	($0.87)

On March 30, 2007, we entered into natural gas liquids swaps to hedge the impact of volatility in the spot prices of natural gas liquids. On September 7, 2007, we entered into additional natural gas liquids swaps. These swaps hedge the spot prices for ethane, propane, iso-butane, normal butane and natural gasoline tracked on the Mont Belvieu, Non-Tet OPIS exchange. The following table summarizes, for the periods indicated, our Mont Belvieu, Non-Tet OPIS natural gas liquids swaps currently in place as of May 7, 2009, through December 31, 2009.

Calendar Year	Volumes (Gal)	Average Price per Gal		Price Range per Gal
April - December 2009	1,699,110	$	1.15	$1.15

On June 24, 2008, Legacy entered into a NYMEX West Texas Intermediate crude oil derivative collar contract that combines a put option or "floor" with a call option or "ceiling." The following table summarizes the oil collar contract currently in place as of May 7, 2009, through December 31, 2012.

Calendar Year	Volumes (Bbls)	Average Floor		Average Ceiling	
April - December 2009	56,800	$	120.00	$	156.30
2010	71,800	$	120.00	$	156.30
2011	68,300	$	120.00	$	156.30
2012	65,100	$	120.00	$	156.30

Financing Activities

Our Revolving Credit Facility

On March 27, 2009, we entered into a new three-year $600 million secured revolving credit facility and retained BNP Paribas as administrative agent to replace our previous four-year, $300 million revolving credit facility with BNP

Paribas as administrative agent. Our obligations under the new credit facility are secured by mortgages on 80% of our oil and natural gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base, currently at $340 million. 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 gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders and any decrease in the borrowing base must be approved by the lenders holding 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66.67% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility so long as it does not increase the borrowing base then in effect. Outstanding borrowings in excess of the borrowing base must be prepaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral.

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

- with respect to ABR loans, the alternate base rate equals the highest of the prime rate, the Federal funds effective rate plus 0.50%, the one-month London interbank rate ("LIBOR") plus 1.50% or the reference bank cost of funds rate, plus an applicable margin ranging from and including 0.75% and 1.50% 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 2.25% and 3.0% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

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

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

- incur indebtedness;
- enter into certain leases;
- grant certain liens;
- enter into certain swaps;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions other than from available cash;
- merge, consolidate or allow any material change in the character of its business; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

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

- consolidated net income (loss) plus interest expense, income taxes, depreciation, depletion, amortization and other similar charges excluding unrealized gains and losses under SFAS 133, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures ("EBITDA"), to interest expense of not less than 2.5 to 1.0;
- total debt to EBITDA of not more than 3.75 to 1.0; and
- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under SFAS 133, which includes the current portion of oil, natural gas and interest rate swaps.

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

- failure to pay any principal when due or any reimbursement amount, interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants or conditions contained in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $1.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or any of our subsidiaries;
- the loan documents cease to be in full force and effect;
- our failing to create a valid lien, except in limited circumstances;
- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of March 27, 2009 and persons who are nominated for election or elected to our general partner's board of directors with the approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) Legacy Reserves GP, LLC ceasing to be our sole general partner;
- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and
- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year.

As of March 31, 2009, Legacy was in compliance with all financial and other covenants of the credit facility.

Off-Balance Sheet Arrangements

None.

Critical Accounting Policies and Estimates

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

- it requires assumptions to be made that were uncertain at the time the estimate was made, and
- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

Please read Note 1 of the Notes to the Condensed Consolidated Financial Statements here and in our annual report on Form 10-K for the period ended December 31, 2008 for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

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

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

Effect if Different Assumptions Used: Units-of-production method to deplete our oil and natural gas properties — A 10% increase or decrease in reserves would have decreased or increased, respectively, our depletion expense for the three-month period ended March 31, 2009 by approximately 10%.

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

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

Effect if Different Assumptions Used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management's judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Unless we expect a well's plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and 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 use the remaining estimated useful life from the year-end reserve report by our independent reserve engineers in estimating when abandonment could be expected for each property. We expect to see our calculations impacted significantly if interest rates continue to rise, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis.

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

We do not specifically designate derivative instruments as cash flow hedges, even though they reduce our exposure to changes in oil, NGL and natural gas prices and interest rate changes. Therefore, the mark-to-market of these instruments is recorded in current earnings. We use market value estimates prepared 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. 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 tables above, we have hedged a significant portion of our future production through 2013. As oil, NGL and natural gas prices rise and fall, our future cash obligations related to these derivatives will rise and fall.

Consolidation of Variable Interest Entity

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

Recently Issued Accounting Pronouncements

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

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

In February 2008, the Financial Accounting Standards Board (“FASB”) issued FASB Staff Position No. 157-2 (“FSP FAS 157-2”). FSP FAS 157-2 deferred the effective date of Statement of Financial Accounting Standards No. 157 (“SFAS 157”) for nonfinancial assets and liabilities to fiscal years beginning after November 15, 2008. Legacy adopted FSP FAS 157-2 effective January 1, 2009 and the adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows. See Note 6 for other disclosures required by SFAS 157 and FSP FAS 157-2.

In March, 2008, the FASB issued SFAS 161. SFAS 161 amends and expands the disclosure requirements of SFAS 133. SFAS 161 requires disclosures related to objectives and strategies for using derivatives; the fair-value amounts of, and gains and losses on, derivative instruments; and credit-risk-related contingent features in derivative agreements. This statement is effective as of the beginning of an entity’s fiscal year beginning after December 15, 2008, which will be the Partnership’s fiscal year 2009. The effect on the Partnership’s disclosures for derivative instruments as a result of the adoption of SFAS 161 in 2009 was not significant since the Partnership does not account for any of its derivatives as cash flow hedges.

During May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (“SFAS 162”). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements presented in conformity with GAAP. SFAS 162 is effective 60 days following the SEC’s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, “The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles.” We do not expect that the adoption of SFAS 162 will have a significant impact on our financial statements.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (“FSP 03-6-1”), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS 128. FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP 03-6-1 is not expected to have a material effect on our net income per unit calculations.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report the independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations. The new disclosure requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Legacy is currently assessing the impact that adoption of this rule will have on its financial disclosures which will vary depending on changes in commodity prices.

In April 2009, the FASB issued FASB Staff Position ("FSP") SFAS No. 141(R)-1 Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies. This FSP amends and clarifies SFAS No. 141 (revised 2007), Business Combinations, to address application issues raised by preparers, auditors, and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP shall be effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Partnership has not made any acquisitions during the first quarter of 2009.

In April 2009, the FASB issued three FSP's to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP SFAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, provides guidelines for making fair value measurements more consistent with the principles presented in SFAS 157. FSP SFAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. These three FSP's are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the provisions of these FSP's for the period ending March 31, 2009. The adoption of these FSP's did not have a material impact on our financial position or results of operations.

Item 3. 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 and NGLs. Pricing for oil, NGLs and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, such as the strength of the global economy.

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

As of March 31, 2009, the fair market value of Legacy’s commodity derivative positions was a net asset of $135.4 million based on NYMEX near month prices of $49.66 per Bbl and $3.78 per MMBtu for oil and natural gas, respectively. As of December 31, 2008, the fair market value of Legacy’s commodity derivative positions was a net asset of $134.9 million based on NYMEX near month prices of $44.60 per Bbl and $5.62 per MMBtu for oil and natural gas, respectively. Due to our asset position on commodity derivatives 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, NGL, and natural gas swaps for 2009 through December 31, 2013, please read “— Investing Activities.”

Interest Rate Risks

At March 31, 2009, Legacy had debt outstanding of $300 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for the three-month period ended March 31, 2009 was 3.69%. A 1% increase in LIBOR on Legacy’s outstanding debt as of March 31, 2009 would result in an estimated $0.36 million increase in annual interest expense as Legacy has entered into interest rate swaps to mitigate the volatility of interest rates through December of 2013 on $264 million of floating rate debt to a weighted-average fixed rate of 3.05%.

Item 4. Controls and Procedures.

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, or the “Exchange Act”) that are designed to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partner’s chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our general partner’s chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of March 31, 2009. Based upon that evaluation and subject to the foregoing, our general partner’s chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

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

There have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended March 31, 2009, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

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

Item 1A. RISK FACTORS

Legacy expects to incur substantial costs in connection with the proposal from Apollo Management VII, LP ("Apollo Management") to acquire all of the outstanding units of Legacy whether or not the proposed transaction is completed.

Legacy already has incurred substantial costs in connection with the proposed transaction with Apollo Management, such as fees of professionals, including fees payable to the independent legal and financial advisors of the conflicts committee of the board of directors, as well as a significant diversion of management resources, and anticipates incurring substantial additional costs and fees in connection with the continuing evaluation of the proposed transaction.

In addition, if the proposed transaction or any other transaction is not completed, Legacy may experience negative reactions from the financial markets, its lenders, customers and employees, which reactions may significantly adversely impact Legacy's business, liquidity, financial condition and results of operations. In particular, if no transaction is completed, the trading price of Legacy's units may significantly decline, as a result of various factors, including the market's perception as to why a transaction was not completed.

The disruptions in the financial markets, the substantial restrictions and financial covenants of our revolving credit facility and any negative redetermination of our borrowing base by our lenders 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 April 1, 2012, limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. The current borrowing base is set at $340 million. As of May 7, 2009, we had $40 million available for borrowing under our revolving credit facility. Due to current commodity price expectations and very limited credit supply, lenders under our revolving credit facility are expected to decrease our borrowing base at the next redetermination scheduled for October 1, 2009. If the lenders were to decrease the borrowing base to a level below our then outstanding borrowings, which are currently at $300 million, the amount exceeding the revised borrowing base would become immediately due and payable. In addition, our lenders may not honor their pro rata share of existing or future total commitments, which may significantly reduce our available borrowing capacity and, as a result, materially adversely affect our financial condition and ability to pay distributions to our unitholders.

Our existing revolving credit facility restricts, among other things, our ability to incur debt and pay distributions, and requires us to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, such as the recent 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.

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

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

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

Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operation — Financing Activities.”

In addition to the other information set forth in this report, you should carefully consider the factors discussed under, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2008, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K for the year ended December 31, 2008 are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.1)
3.2	Amended and Restated Limited Partnership Agreement of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	Amendment No.1, dated December 27, 2007, to the Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Current Report on Form 8-K (File No. 001-33249) filed January 2, 2008, Exhibit 3.1)
3.4	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.5	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
4.1	Registration Rights Agreement dated June 29, 2006 between Henry Holding 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 thereto (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 (File No. 001-33249) filed May 14, 2007, Exhibit 4.4)
10.1	Amended and Restated Credit Agreement dated as of March 27, 2009 among Legacy Reserves LP, BNP Paribas, as administrative agent, Wachovia 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 April 1, 2009, Exhibit 10.1)
31.1*	Rule 13a-14(a) Certifications (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	Rule 13a-14(a) Certifications (under Section 302 of the Sarbanes-Oxley Act of 2002)
32.1*	Section 1350 Certifications (under Section 906 of the Sarbanes-Oxley Act of 2002)

* Filed herewith

LEGACY RESERVES LP
SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

LEGACY RESERVES LP

By: Legacy Reserves GP, LLC, its General Partner

May 8, 2009	By:	/s/ Steven H. Pruett Steven H. Pruett President, Chief Financial Officer and Secretary (On behalf of the Registrant and as Principal Financial Officer)