LEGACY RESERVES LP
Form 10-Q
November 09, 2007

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 September 30, 2007

OR

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

SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number 1-33249

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

Delaware (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 checkmark 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 is a large accelerated filer, an accelerated filed, or a non-accelerated filer. See definition of “accelerated filer and larger accelerated filer” in Rule 12b-2 of the Exchange Act.:

o Large accelerated filer o Accelerated filer x Non-accelerated filer

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

29,708,965 units representing limited partner interests in the registrant were outstanding as of November 9, 2007.

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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 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.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

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

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

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

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

Mcf. One thousand cubic feet.

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

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

NGLs 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 PDN’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 exploitation. 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

	December 31, 2006	September 30, 2007
Current assets:		
Cash and cash equivalents	$ 1,061,852	$ 4,358,522
Accounts receivable, net:		
Oil and natural gas	7,599,915	12,596,594
Joint interest owners	4,345,334	3,650,636
Affiliated entities and other (Note 4)	21,336	9,907
Fair value of derivatives (Note 6)	5,102,083	301,534
Prepaid expenses and other current assets	90,609	649,654
Total current assets	18,221,129	21,566,847
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, at cost, using the successful efforts method of accounting:	289,518,708	406,356,304
Unproved properties	68,275	78,025
Accumulated depletion, depreciation and amortization	(42,006,485)	(61,373,332)
	247,580,498	345,060,997
Other property and equipment, net of accumulated depreciaton and amortization of $51,108 and $177,166, respectively	303,750	679,495
Deposits on pending acquisitions	-	4,637,644
Operating rights, net of amortization of $295,314 and $724,942, respectively	6,721,358	6,291,730
Fair value of derivatives (Note 6)	-	25,293
Other assets, net of amortization of $167,179 and $306,883, respectively	541,743	738,235
Investment in equity method investee (Note 3)	-	86,731
Total assets	$ 273,368,478	$ 379,086,972

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

LIABILITIES AND UNITHOLDERS' EQUITY

	December 31, 2006	September 30, 2007
Current liabilities:		
Accounts payable	$ 2,931,627	$ 681,293
Accrued oil and natural gas liabilities	5,881,612	8,566,783
Fair value of derivatives (Note 6)	-	8,124,905
Asset retirement obligation (Note 7)	553,579	470,518
Other (Note 9)	1,466,693	2,882,551
Total current liabilities	10,833,511	20,726,050
Long-term debt (Note 2)	115,800,000	93,000,000
Asset retirement obligation (Note 7)	5,939,201	7,045,527
Fair value of derivatives (Note 6)	2,006,547	13,768,328
Total liabilities	134,579,259	134,539,905
Commitments and contingencies (Note 5)		
Unitholders' equity:		
Limited partners' equity - 18,395,233 and 26,021,518 units issued		
and outstanding at December 31, 2006 and September 30, 2007, respectively	138,653,452	244,440,705
General partner's equity (approximately 0.1%)	135,767	106,362
Total unitholders' equity	138,789,219	244,547,067
Total liabilities and unitholders' equity	$ 273,368,478	$ 379,086,972

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
Revenues:				
Oil sales	$ 13,204,380	$ 22,441,858	$ 32,443,950	$ 51,396,169
Natural gas liquid sales	-	1,713,657	-	2,890,994
Natural gas sales	4,238,937	5,240,788	10,822,193	13,776,326
Realized and unrealized gain (loss) on oil and natural gas swaps (Note 6)	18,605,638	(6,435,752)	5,533,553	(20,151,656)
Total revenues	36,048,955	22,960,551	48,799,696	47,911,833
Expenses:				
Oil and natural gas production	4,166,766	7,580,473	10,159,887	18,408,152
Production and other taxes	1,029,511	1,886,122	2,710,392	4,360,881
General and administrative	1,186,884	1,443,190	3,265,163	6,039,371
Depletion, depreciation, amortization and accretion	5,346,432	6,959,351	12,701,726	19,065,064
Impairment of long-lived assets	8,572,859	950,174	8,572,859	1,229,874
Loss on disposal of assets	-	156,240	-	387,373
Total expenses	20,302,452	18,975,550	37,410,027	49,490,715
Operating income (loss)	15,746,503	3,985,001	11,389,669	(1,578,882)
Other income (expense):				
Interest income	55,226	54,284	93,659	205,443
Interest expense (Notes 2 and 6)	(1,857,331)	(1,905,234)	(4,511,679)	(3,423,286)
Equity in income (loss) of partnerships	-	29,690	(317,788)	40,600
Other	-	-	14,910	1,013
Net income (loss)	$ 13,944,398	$ 2,163,741	$ 6,668,771	$ (4,755,112)
Net income (loss) per unit - basic and diluted (Note 8)	$ 0.76	$ 0.08	$ 0.42	$ (0.19)
Weighted average number of units used in computing net income (loss) per unit -				
basic	18,386,817	26,021,518	15,952,509	25,492,521
diluted	18,386,817	26,072,886	15,952,509	25,492,521

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENT OF UNITHOLDERS' EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2007
(UNAUDITED)

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders' Equity
Balance, December 31, 2006	18,395,233	$ 138,653,452	$ 135,767	$ 138,789,219
Net proceeds from initial public equity offering	6,900,000	121,554,464	-	121,554,464
Compensation expense on restricted unit awards issued to employees	-	255,492	-	255,492
Vesting of Restricted Units	20,038	-	-	-
Units issued to Greg McCabe in exchange for oil and natural gas properties	95,000	2,270,500	-	2,270,500
Units issued to Nielson & Associates, Inc. in exchange for oil and natural gas properties	611,247	15,751,835	-	15,751,835
Reclass prior period compensation cost on unit options granted to employees to adjust for conversion to liability method as described in FAS 123-R	-	(115,199)	(115)	(115,314)
Distributions to unitholders, $1.24 per unit	-	(29,178,070)	(25,947)	(29,204,017)
Net loss	-	(4,751,769)	(3,343)	(4,755,112)
Balance, September 30, 2007	26,021,518	$ 244,440,705	$ 106,362	$ 244,547,067

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2007
Cash flows from operating activities:		
Net income (loss)	$ 6,668,771	$ (4,755,112)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	12,701,726	19,065,064
Amortization of debt issuance costs	318,344	139,704
Impairment of long-lived assets	8,572,859	1,229,874
(Gain) loss on derivatives	(5,533,553)	20,426,216
Equity in (income) loss of partnership	317,788	(40,600)
Amortization of unit-based compensation	457,559	(68,673)
Loss on disposal of assets	-	387,373
Changes in assets and liabilities:		
Increase in accounts receivable, oil and natural gas	(6,302,693)	(4,996,679)
(Increase) decrease in accounts receivable, joint interest owners	(2,498,932)	694,698
(Increase) decrease in accounts receivable, other	(449,850)	11,429
Increase in other current assets	(702,386)	(559,045)
Increase (decrease) in accounts payable	687,111	(2,250,334)
Increase in accrued oil and natural gas liabilities	3,819,783	2,685,171
Increase in due to affiliates	1,246,811	-
Increase in other current liabilities	2,514,897	1,330,260
Total adjustments	15,149,464	38,054,458
Net cash provided by operating activities	21,818,235	33,299,346
Cash flows from investing activities:		
Investment in oil and natural gas properties	(45,353,007)	(98,267,074)
Increase in deposit on pending acquisition	-	(4,637,644)
Investment in other equipment	(200,124)	(501,804)
Investment in operating rights	(7,016,672)	-
Collection of notes receivable	924,441	-
Net cash settlements on oil and natural gas swaps	(2,182,065)	4,235,726
Investment in equity method investee	-	(46,131)
Net cash used in investing activities	(53,827,427)	(99,216,927)
Cash flows from financing activities:		
Proceeds from long-term debt	112,800,000	111,000,000
Payments of long-term debt	(73,189,791)	(133,800,000)
Payments of debt issuance costs	(292,803)	(336,196)
Proceeds from issuance of units, net	77,894,654	121,554,464
Redemption of Founding Investors' units	(69,938,000)	-
Dividend - reimbursement of offering costs paid by MBN Management LLC	(1,200,229)	-
Capital contributed by owner	19,356	-
Cash not acquired in Legacy formation transactions	(3,104,304)	-
Distributions to unitholders	(11,290,387)	(29,204,017)
Net cash provided by financing activities	31,698,496	69,214,251
Net increase (decrease) in cash and cash equivalents	(310,696)	3,296,670

Cash and cash equivalents, beginning of period		1,954,923		1,061,852
Cash and cash equivalents, end of period	$	1,644,227	$	4,358,522

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2006		2007	
Non-Cash Investing and Financing Activities:				
Asset retirement obligation costs and liabilities	$	1,467,241	$	-
Asset retirement obligations associated with property acquisitions	$	1,877,520	$	1,023,447
Non-controlling interests' share of net financing costs of MBN				
Properties LP capitalized to oil and natural gas properties	$	164,202	$	-
Units issued to MBN Properties LP in exchange for the				
non-controlling interests' share of oil and natural gas properties	$	31,743,934	$	-
Units issued to Brothers Group in exchange for:				
Oil and natural gas properties	$	105,298,794	$	-
Other property and equipment	$	107,275	$	-
Units issued to H2K Holdings Ltd. in exchange for oil and				
natural gas properties	$	1,419,483	$	-
Oil and natural gas hedge liabilities assumed from the				
Brothers Group and H2K Holdings Ltd.	$	3,147,152	$	-
Units issued in exchange for oil and				
natural gas properties	$	2,346,000	$	18,022,335
Deemed dividend to Moriah Group owners for accounts not acquired				
in Legacy formation transaction:				
Accounts receivable, oil and natural gas	$	4,248,157	$	-
Accounts receivable, joint interest owners	$	249,627	$	-
Accounts receivable, other	$	539,968	$	-
Other assets	$	891,300	$	-
Accounts payable	$	(213,941)	$	-
Accrued oil and natural gas liabilities	$	(1,520,709)	$	-
Due to affiliates	$	(1,254,215)	$	-
Other liabilities	$	(2,166,276)	$	-

See accompanying notes to condensed consolidated financial statements.

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

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

Legacy Reserves LP and its affiliated entities are referred to as Legacy or LRLP 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 SEC. These condensed consolidated financial statements should be read in connection with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2006.

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

On March 15, 2006, Legacy, as the successor entity to the Moriah Group (defined below), completed a private equity offering in which it (1) issued 5,000,000 limited partnership units at a gross price of $17.00 per unit, netting $76.8 million after initial purchaser's discount, placement agent's fee and expenses, (2) acquired certain oil and natural gas properties (Note 3) and (3) redeemed 4.4 million units for $69.9 million from the Brothers Group, H2K Holdings and MBN Properties, who, along with the Moriah Group, are its "Founding Investors." The Moriah Group was treated as the acquiring entity in this transaction, hereinafter referred to as the "Legacy Formation." Because the combination of the businesses that comprised the Moriah Group was a reorganization of entities under common control, the combination of these businesses was reflected retroactively at carryover basis in these condensed consolidated financial statements. The accounts presented for periods prior to the Legacy Formation transaction are those of the Moriah Group.

On January 18, 2007, Legacy closed its initial public offering ("IPO") of 6,900,000 limited partnership units at an IPO price of $19.00 per unit. Net proceeds to the partnership after underwriting discounts and estimated offering expenses were approximately $122 million, which were used to repay all indebtedness outstanding under the partnership's credit facility and for general partnership purposes.

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 our business and affairs; the general partner shall conduct, direct and manage LRLP's activities.

- The general partner may be removed if such removal is approved by the unitholders holding at least 66 2/3 percent of the outstanding units, including units held by LRLP's general partner and its affiliates 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.

As used herein, the term Moriah Group refers to Moriah Resources, Inc. ("MRI"), Moriah Properties, Ltd. ("MPL"), the oil and natural gas interests individually owned by Dale A. and Rita Brown and the accounts of MBN Properties LP on a consolidated basis unless the context specifies otherwise. Prior to March 15, 2006, the accompanying financial statements include the accounts of the Moriah Group. From March 15, 2006, the accompanying financial statements also include the results of operations of the oil and natural gas properties acquired in the Legacy Formation transaction.

All significant intercompany accounts and transactions have been eliminated. The Moriah Group consolidated MBN Properties LP as a variable interest entity under FASB Interpretation Number “FIN” 46R since the Moriah Group was the primary beneficiary of MBN Properties LP. The partners, shareholders and owners of these entities have other investments, such as real estate, that are held either individually or through other legal entities that are not presented as part of these financial statements.

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

The accompanying financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred. These condensed consolidated financial statements as of September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006 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 amounts in the prior period financial statements have been reclassified to conform to the current period presentation. 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 and nine months ended September 30, 2007 and 2006.

(2) Credit Facility

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

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

As an integral part of the Legacy Formation, Legacy entered into a new credit agreement with a new senior credit facility (the “Legacy Facility”) with the same lending group that participated in the New Facility of the Moriah Group. Legacy’s oil and natural gas properties are pledged as collateral for any borrowings under the Legacy Facility. The terms of the Legacy Facility permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $300 million. The borrowing base under the Legacy Facility, which was initially set at $130 million, is re-determined every six months and will be adjusted based upon changes in the fair market value of Legacy’s oil and natural gas assets. Interest on the Legacy Facility is payable monthly and was charged in accordance with Legacy’s selection of a LIBOR rate plus 1.25% to 1.875%, or prime rate up to prime rate plus 0.375%, dependent on the percentage of the borrowing base which is drawn. On March 15, 2006, Legacy borrowed $65.8 million from the new lending group as part of the Legacy Formation. On May 3, 2007, Legacy’s bank group increased Legacy’s borrowing base to $150 million as part of the semi-annual re-determination. On October 24, 2007, the Legacy Facility was amended, increasing the borrowing base to $225 million and the borrowing capacity to $500 million. Pursuant to this amendment, interest on debt outstanding is charged based on Legacy’s selection of a LIBOR rate plus 1.00% to 1.75%, or the alternate base rate which equals the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.25%.

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

As of September 30, 2007, Legacy had outstanding borrowings of $93.0 million at an interest rate of 6.92%. Legacy had approximately $101.7 million of availability remaining under the Legacy Facility as of September 30, 2007. For the three-month and nine-month period ended September 30, 2007, Legacy paid $1,295,619 and $2,258,164 of interest expense on the Legacy Facility, respectively. The Legacy Facility contains certain loan covenants requiring minimum financial ratio coverages, involving the current ratio and EBITDA to interest expense. At December 31, 2006 and September 30, 2007, Legacy was in compliance with all aspects of the Legacy Facility.

Long-term debt consists of the following at December 31, 2006 and September 30, 2007:

	December 31, 2006	**September 30, 2007**
Legacy facility- due March 2010	$ 115,800,000	$ 93,000,000

(3) Acquisitions

Legacy Formation Acquisition

On March 15, 2006, LRLP completed a private equity offering in which it issued 5,000,000 units representing limited partner interests at a gross price of $17.00 per unit, netting $76.8 million after initial purchaser's discount, placement agent fees and expenses. Simultaneous with the completion of this offering, Legacy purchased the oil and natural gas properties of the Moriah Group, Brothers Group, H2K Holdings Ltd. and the Charitable Support Foundations, Inc. and its affiliates. Legacy also purchased the oil and natural gas properties owned by MBN Properties, LP. In the case of the Moriah Group, the Brothers Group and H2K Holdings Ltd. those entities exchanged their oil and natural gas properties for units representing limited partner interests. The purchase of the oil and natural gas properties owned by the charitable foundations was solely for cash of $7.7 million. The Founding Investors exchanged 4.4 million of their units for $69.9 million in cash. The Moriah Group has been treated as the acquiring entity in the Legacy Formation. Accordingly, the accounts of the businesses acquired from the Moriah Group have been reflected retroactively at carryover basis in the consolidated financial statements, and the units issued to acquire them have been accounted for as a recapitalization. The net assets of the other businesses acquired and the units issued in exchange for them have been reflected at fair value and included in the statement of operations from the date of acquisition. With the exception of its assumption of liabilities associated with the oil and natural gas swaps it acquired, the other depreciable assets of the Brothers Group (office furniture and equipment and vehicles) and certain unamortized deferred financing costs of the Moriah Group, LRLP did not acquire any other assets or liabilities of the Moriah Group, the Brothers Group, H2K Holdings Ltd. or the Charitable Support Foundations, Inc. and its affiliates. The removal of the other assets and liabilities of the Moriah Group was reflected as a deemed dividend in the quarter ended March 31, 2006.

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

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

In addition to the 18,240,068 units issued at Legacy Formation, 52,616 restricted units were issued to employees of Legacy concurrent with, but not as a part of, the Legacy Formation (Note 9).

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

	Number of Units at $17.00 per unit		Purchase Price of Assets Acquired
Brothers Group	6,200,358	$	105,406,069
H2K Holdings Ltd.	83,499		1,419,483
Cash paid to three charitable foundations	-		7,682,854
Total purchase price before liabilities assumed			114,508,406
Plus:			
Oil and natural gas swap liabilities assumed			3,147,152
Asset retirement obligations incurred			1,467,241
Less:			
Office furniture, equipment and vehicles acquired			(107,275)
Total purchase price allocated to oil and natural gas properties acquired		$	119,015,524

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

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

Plus:			
Elimination of deferred financing costs related to			
non-controlling interests' share of MBN Properties LP			164,202
Reimbursement of Brothers Group's share of MBN			
Management LLC losses from inception through			
March 14, 2006			780,239
MBN Properties LP purchase price to allocate			
to oil and natural gas properties		$	32,688,375
Units related to purchase of non-controlling interest	1,867,290		
Units related to interest previously owned by Moriah Group	1,295,148		
Total units issued to MBN Properties LP	3,162,438		

Larron Acquisition

On June 29, 2006, Legacy purchased a 100% working interest and an approximate 82% net revenue interest in producing leases located in the Farmer Field for $5.7 million. The conveyance of the leases was effective April 1, 2006. The $5.6 million net purchase price was allocated with $4.6 million recorded as lease and well equipment and $1.0 million of leasehold costs. Asset retirement obligations in the amount of $328,867 were recognized in connection with this acquisition. The operations of these Farmer Field properties have been included from their acquisition on June 29, 2006.

South Justis Unit Acquisition

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

Kinder Morgan Acquisition

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

Binger Acquisition

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

Ameristate Acquisition

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

TSF Acquisition

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

Raven Shenandoah Acquisition

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

Raven OBO Acquisition

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

Pro Forma Operating Results

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

	September 30, 2006	September 30, 2007
	(In thousands)	
Revenues, excluding hedging gains and losses	$ 77,416	$ 78,525
Revenues, net of hedging gains and losses	$ 81,645	$ 58,373
Net income	$ 13,478	$ (3,345)
Earnings (loss) per unit:		
Basic	$ 0.71	$ (0.13)
Diluted	$ 0.71	$ (0.13)
Units used in computing earnings (loss) per unit:		
Basic	19,003,210	25,727,616
Diluted	19,014,085	25,727,616

(4) Related Party Transactions

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

The Moriah Group did not directly employ any persons or directly incur any office overhead. Substantially all general and administrative services were provided by Petroleum Strategies, Inc. which employed all personnel and paid for all employee salaries, benefits, and office expenses. Petroleum Strategies Inc. charged the Moriah Group for such services in an amount which was intended to be equal to the actual expenses it incurred. Amounts charged were

$444,827 and $0 for the nine months ended September 30, 2006 and 2007, respectively. On April 1, 2006, following the Legacy Formation, certain employees of Petroleum Strategies, Inc. and Brothers Production Company Inc. became employees of Legacy. For the period from March 15, 2006 to September 30, 2006, Brothers Production Company Inc. provided $47,236 of transition administrative services to Legacy.

Legacy uses Lynch, Chappell and Alsup for legal services. Alan Brown, son of Dale Brown and brother of Cary Brown, is a less than ten percent shareholder in this firm. Legacy paid legal fees to Lynch, Chappell and Alsup of $39,003 and $82,143 for the nine months ended September 30, 2006 and 2007, 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.

(6) Derivative Financial Instruments

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

All of these price-risk management transactions are considered derivative instruments and accounted for in accordance with SFAS No. 133 — *Accounting for Derivative Instruments and Hedging Activities.* These derivative instruments are intended to 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 current period earnings.

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

For the three and nine months ended September 30, 2006 and 2007, Legacy included in revenue realized and unrealized losses related to its oil and natural gas derivatives. The impact on total revenue from hedging activities was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2007**	**2006**	**2007**
Crude oil derivative contract settlements	$ (5,798,140)	$ (845,744)	$ (6,897,833)	$ 1,198,916
Natural gas liquid derivative contract settlements	-	(118,044)	-	(159,395)
Natural gas derivative contract settlements	1,669,838	1,372,154	4,715,768	3,196,205
Unrealized change in fair value - oil contracts	19,770,172	(7,677,256)	1,342,276	(20,860,444)
Unrealized change in fair value - natural gas liquid contracts	-	(650,285)	-	(940,557)
Unrealized change in fair value - natural gas contracts	2,963,768	1,483,423	6,373,342	(2,586,381)
	$ 18,605,638	$ (6,435,752)	$ 5,533,553	$ (20,151,656)

As of September 30, 2007, Legacy had the following NYMEX West Texas Intermediate crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Calendar Year	Annual Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2007	273,578	$ 68.81	$64.15 - $75.70

2008	1,025,249	$	68.57	$62.25 - $73.45
2009	948,013	$	66.65	$61.05 - $71.40
2010	883,445	$	65.26	$60.15 - $71.15
2011	665,040	$	70.17	$67.33 - $71.40
2012	549,600	$	70.04	$67.72 - $71.15

As of September 30, 2007, Legacy had the following NYMEX Henry Hub, ANR-OK and Waha natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	**Annual Volumes (MMBtu)**		**Average Price per MMBtu**	**Price Range per MMBtu**
2007	656,192	$	8.59	$6.85 - $10.01
2008	2,402,970	$	8.17	$6.85 - $10.58
2009	2,217,470	$	8.01	$6.85 - $10.18
2010	1,962,755	$	7.74	$6.85 - $9.73
2011	694,024	$	7.21	$6.85 - $7.51
2012	404,436	$	7.07	$6.85 - $7.30

As of September 30, 2007, 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 follow Waha more closely than NYMEX:

Calendar Year	Annual Volumes (Mcf)	Basis Differential per Mcf
2007	390,000	($0.88)
2008	1,422,000	($0.84)
2009	1,320,000	($0.68)
2010	1,200,000	($0.57)

As of September 30, 2007, Legacy had the following Mont Belvieu, Non-Tet OPIS natural gas liquids swaps paying floating natural gas liquids prices and receiving fixed prices for a portion of its future natural gas liquids production as indicated below:

Calendar Year	Annual Volumes (Gal)	Average Price per Gal	Price Range per Gal
2007	1,682,838	$ 1.32	$0.79 - $1.68
2008	6,458,004	$ 1.27	$0.66 - $1.62
2009	2,265,480	$ 1.15	$1.15

On August 29, 2007, Legacy entered into LIBOR interest rate swaps beginning in October of 2007 and extending through November 2011. The swap transaction has Legacy paying its counterparty floating rates and receiving fixed rates ranging from 4.8075% to 4.82%, per annum, on a total notional amount of $54 million. The swaps are settled on a quarterly basis, beginning in January of 2008 and ending in November of 2011. The table below summarizes the interest rate swap position as of September 30, 2007.

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

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

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at September 30, 2007
$29,000,000	4.8200%	10/16/2007	10/17/2011	($149,901)
$13,000,000	4.8100%	11/16/2007	11/16/2011	(64,927)
$12,000,000	4.8075%	11/28/2007	11/28/2011	(59,732)
Total Fair Market Value				($274,560)

(7) Asset Retirement Obligation

Statement of Financial Accounting Standards “SFAS” No. 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 year ended December 31, 2006 and nine months ended September 30, 2007.

	December 31, 2006	**September 30, 2007**
Asset retirement obligation - beginning of period	$ 2,302,147	$ 6,492,780
Liabilities incurred in Legacy formation	1,467,241	-
Liabilities incurred with properties acquired	1,888,954	1,026,335
Liabilities incurred with properties drilled	22,882	-
Liabilities settled during the period	(213,343)	(297,338)
Current period accretion	242,432	294,268
Current period revisions to oil and natural gas properties	782,467	-
Asset retirement obligation - end of period	$ 6,492,780	$ 7,516,045

(8) Earnings Per Unit

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Income available to unitholders	$ 13,944	$ 2,164	$ 6,669	$ (4,755)
Weighted average number of units outstanding	18,386,817	26,021,518	15,952,509	25,492,521
Effect of dilutive securities:				
Unit options	-	30,700	-	-
Restricted units	-	20,668	-	-
Weighted average units and potential units outstanding	18,386,817	26,072,886	15,952,509	25,492,521
Basic earnings per unit	$ 0.76	$ 0.08	$ 0.42	$ (0.19)
Diluted earnings per unit	$ 0.76	$ 0.08	$ 0.42	$ (0.19)

(9) Unit-Based Compensation

Long Term Incentive Plan

Concurrent with the Legacy Formation on March 15, 2006, a Long-Term Incentive Plan ("LTIP") for Legacy was created and Legacy adopted SFAS No. 123(R)-*Share-Based Payment*. Legacy adopted the Legacy Reserves LP Long-Term Incentive Plan for its employees, consultants and directors, its affiliates and its general partner. The awards under the 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 September 30, 2007 grants of awards net of forfeitures covering 392,460 units had been made. The LTIP is administered by the compensation committee of the board of directors of Legacy's general partner.

SFAS No. 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 No. 123(R) to recognize the cost associated with unit options. However, SFAS No. 123(R) stipulates that "if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if 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 No. 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.

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

On June 27, 2007, Legacy granted 3,000 phantom units to an employee. On July 16, 2007, Legacy granted 5,000 phantom units to an employee. The phantom units awarded vest ratably over a five year period, beginning on the date of grant. In conjunction with this grant, the employees are entitled to dividend equivalent rights ("DER's") for unvested units held at the date of dividend payment. Compensation expense related to the phantom units and associated DER's was $22,027 for the nine months ended September 30, 2007.

On August 20, 2007, the board of directors of Legacy's general partner, upon recommendation from the Compensation Committee, approved phantom unit awards which may award up to 175,000 units to five key executives of Legacy based on achievement of targeted annual MLP distribution levels over a base amount of $1.64 per unit. These awards are to be determined annually based solely on the annualized level of per unit distributions for the fourth quarter of each calendar year and subsequently vested over a 3 year period. There is a range of 0% to 100% of the distribution levels at which the performance condition may be met. For each quarter, management recommends to the board an appropriate level of per unit distribution based on available cash of Legacy. This level of distribution is approved by the board subsequent to management's recommendation. Probable issuances for the purposes of calculating compensation expense associated therewith are determined based on management's determination of probable future distribution levels. 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. Compensation expense related to the phantom units was $8,435 for the nine months ended September 30, 2007.

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 the date of grant. Compensation expense related to restricted units was $184,875 and $255,492 for the nine months ended September, 30, 2006 and 2007, respectively. As of September 30, 2007, there was a total of $581,439 of unrecognized compensation expense related to the non-vested portion of these restricted units. At September 30, 2007, 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 September 30, 2007 does not include 45,078 units related to unvested restricted unit awards.

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

During the year ended December 31, 2006, Legacy issued 273,000 unit option awards to officers and employees which vest ratably over a three-year period. All options granted in 2006 expire five years from the grant date and are exercisable when they vest. During the nine month period ended September 30, 2007, Legacy issued 83,000 unit option awards to employees which vest ratably over a three-year period. During the nine-month period ended September 30, 2007, Legacy issued 66,116 unit option awards which cliff-vest at the end of a three-year period. All options granted in 2007 expire five years from the grant date and are exercisable when they vest.

For the nine-month period ended September 30, 2007, Legacy recorded $855,345 of compensation expense based on its use of the Black-Scholes model to estimate the September 30, 2007 fair value of these unit option awards and options exercised during the period. As of September 30, 2007, there was a total of $1,262,999 of unrecognized compensation costs related to the non-vested portion of these unit option awards. At September 30, 2007, this cost was expected to be recognized over a weighted-average period of 2.10 years. Compensation expense is based upon the fair value as of September 30, 2007 and is recognized as a percentage of the service period satisfied. Since Legacy is a new public company and has minimal trading history, it has used an estimated volatility factor of approximately 42% based upon the historical trends of a representative group of publicly-traded companies in the energy industry and employed the fair value method to estimate the September 30, 2007 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 No. 123(R), the Company will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $1.68 per unit.

A summary of option activity for the nine months ended September 30, 2007 is as follows:

	Units	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term
Outstanding at January 1, 2007	260,000	$ 17.01	
Granted	149,116	$ 23.28	
Exercised	(23,038)	$ 17.00	
Forfeited	(16,656)	$ 17.09	
Outstanding at September 30, 2007	369,422	$ 19.54	4.1 years
Options exercisable at September 30, 2007	61,798	$ 17.01	-

The following table summarizes the status of the Legacy's non-vested unit options since January 1, 2007:

	Non-Vested Options	
	Number of Units	Weighted-Average Fair Value
Non-vested at January 1, 2007	260,000	$ 2.62
Granted	149,116	$ 4.54
Vested - Unexercised	(61,798)	$ 6.10
Vested - Exercised	(23,038)	$ 10.14
Forfeited	(16,656)	$ 9.56
Non-vested at September 30, 2007	307,624	$ 5.47

Legacy has used a weighted-average risk free interest rate of 4.6% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at September 30, 2007 whose term is consistent with the expected life of the unit options. Expected life represents the period of time that options 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.

	Nine Months Ended September 30, 2007
Expected life (years)	5
Annual interest rate	4.6%
Annual distribution rate per unit	$ 1.68
Volatility	42%

(10) Subsequent Events

On August 30, 2007, Legacy entered into a definitive purchase agreement to acquire certain oil and natural gas producing properties from a private party for a cash purchase price of $15.3 million, subject to customary purchase price adjustments. The properties are located in the Permian Basin. The acquisition closed on October 1, 2007. This acquisition will be accounted for as a purchase of oil and natural gas assets.

On September 4, 2007, Legacy entered into a definitive purchase agreement to acquire certain oil and natural gas producing properties from private parties for a cash purchase price of $60.5 million, subject to customary purchase price adjustments. The properties are located in the Permian Basin. The acquisition closed on October 1, 2007. This acquisition will be accounted for as a purchase of oil and natural gas assets.

On October 24, 2007, Legacy entered into a Third Amendment to Credit Agreement (the “Third Amendment”) to the Legacy Facility. Pursuant to the Third Amendment, the maximum credit amount has been increased to $500 million and the borrowing base has been increased to $225 million. Additionally, the Legacy Facility provides that Legacy may elect that borrowing be comprised entirely of alternate base rate (ABR) loans or Eurodollar Loans. Under the Third Amendment, interest on the loans is determined, with respect to ABR Loans, the alternate base rate equals the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.25%; and with respect to Eurodollar loans, interest is calculated using the London interbank rate (LIBOR) plus an applicable margin between 1.00% and 1.75%.

On October 18, 2007, Legacy’s Board of Directors approved a distribution of $0.43 per unit payable on November 14, 2007 to unitholders of record on October 31, 2007.

Legacy entered into a Unit Purchase Agreement (the “Purchase Agreement”), dated effective as of November 7, 2007, with Legacy Reserves GP, LLC and certain institutional investors (the “Purchasers”) to sell an aggregate of 3,642,369 units representing limited partner interests in LRLP (the “Units”) in a private placement (the “Private Placement”). The negotiated purchase price for the Units in the Purchase Agreement was $20.50 per unit, or approximately $75 million in the aggregate.

The Private Placement closed, and 3,642,369 Units were issued, on November 8, 2007. LRLP will use the net proceeds from the Private Placement primarily to reduce debt currently outstanding under the Legacy Facility. The borrowings were used to finance the acquisition of properties in the Texas Panhandle and Permian Basin which closed during October 2007 for approximately $74 million. The Private Placement pursuant to the Purchase Agreement is being made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof.

In connection with the Purchase Agreement, LRLP also entered into a Registration Rights Agreement dated November 8, 2007 (the “Registration Rights Agreement”) with the Purchasers. The Registration Rights Agreement requires LRLP to file a shelf registration statement with the Securities and Exchange Commission (“SEC”) to register the Units as soon as practicable after the closing date of the Private Placement, but in any event within 90 days after the closing, which occurred on November 8, 2007. In addition, the Registration Rights Agreement requires LRLP to use its commercially reasonable efforts to cause the shelf registration statement to become effective no later than 180 days after the closing date of the Private Placement (the “Target Effective Date”). If the registration statement covering the Units is not declared effective by the SEC within 180 days after the closing date of the Private Placement (the “Target Effective Date”), then LRLP will be liable to each Purchaser for liquidated damages, and not as a penalty, of 0.25% of the product of $20.50 (the purchase price) times the number of Units purchased by the Purchaser (the “Liquidated Damages Amount”) per the 30-day period for the first 30 days following the Target Effective Date, increasing by an additional 0.25% of the Liquidated Damages Amount per each non-overlapping 30-day period for each subsequent 30-day period subsequent to the 30 days following the Target Effective Date, up to a maximum of

1.00% of the Liquidated Damages Amount per each non-overlapping 30-day period (i.e., 0.25% for 1-30 days; 0.5% for 31-60 days; 0.75% for 61-90 days; and 1.0% thereafter); *provided*, that the aggregate amount of liquidated damages payable by LRLP under the Registration Rights Agreement to each Purchaser shall not exceed 10.0% of the Liquidated Damages Amount with respect to such Purchaser. The Registration Rights Agreement also provides for the payment of liquidated damages in the event LRLP suspends the use of the shelf registration statement in excess of permitted periods. The Registration Rights Agreement also gives certain Purchasers piggyback registration rights with other shelf registration statements under certain circumstances.

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 our:

- business strategy;
- financial strategy;
- drilling locations;
- oil and natural gas reserves;
- technology;
- realized oil and natural gas prices;
- production volumes;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- 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," "t negative of 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 we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will 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, 2006 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. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Overview

We were formed in October 2005. Upon completion of our private equity offering and as a result of the related Legacy Formation on March 15, 2006, we acquired oil and natural gas properties and business operations from our Founding

Investors and three charitable foundations. Although we were the surviving entity for legal purposes, the formation transactions are treated as a purchase with Moriah Properties, Ltd. and its affiliates, or the Moriah Group, being considered, on a combined basis, as the acquiring entity for accounting purposes. Therefore, the accounts reflected in our historical financial statements prior to March 15, 2006 are those of the Moriah Group.

On January 18, 2007, we closed our IPO of 6,900,000 units representing limited partner interests at an IPO price of $19.00 per unit. Net proceeds to the partnership after underwriting discounts and estimated offering expenses were approximately $122 million, all of which were used to repay the $115.8 million of indebtedness outstanding under our credit facility and for general partnership purposes.

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

Because of our rapid growth through acquisitions and development of properties, historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results.

The operating results of the properties acquired in the Legacy Formation are included in the results of operations from March 15, 2006, the operating results of the South Justis Unit properties and the Farmer Field properties acquired on June 29, 2006 have been included from July 1, 2006, the operating results of the Kinder Morgan properties have been included from August 1, 2006, the operating results of the Binger properties have been included from April 16, 2007, the operating results of the Ameristate properties have been included from May 1, 2007, the operating results of the TSF properties have been included from May 25, 2007, the operating results of the Raven Shenandoah properties have been included from May 31, 2007 and the operating results of the Raven OBO properties have been included from August 3, 2007.

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

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

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

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

We face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. We attempt to overcome this natural decline by utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary (CO_2) recovery methods to repressure the reservoir and recover additional oil, drilling to find additional reserves, restimulating 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, obtain regulatory approvals and contract drilling rigs and personnel.

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

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

Production and Operating Costs Reporting

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the optimal level. Accordingly, we continuously monitor our production and operating costs per well to determine if any wells or properties should be shut in, 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 and counties in which our properties are located. These taxes are reported as production taxes and are a percentage of oil and natural gas revenue. Ad valorem taxes are a percentage of property valuation. Gathering and transportation costs are generally borne by the purchasers of our oil and natural gas as the price paid for our products reflects these costs.

Operating Data

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2007**	**2006 (a)**	**2007**
Revenues:				
Oil sales	$ 13,204,380	$ 22,441,858	$ 32,443,950	$ 51,396,169
Natural gas liquid sales	-	1,713,657	-	2,890,994
Natural gas sales	4,238,937	5,240,788	10,822,193	13,776,326
Realized gain (loss) on oil swaps	(5,798,140)	(845,744)	(6,897,833)	1,198,916
Realized loss on natural gas liquid swaps	-	(118,044)	-	(159,395)
Realized gain on natural gas swaps	1,669,838	1,372,154	4,715,768	3,196,205
Unrealized gain (loss) on oil swaps	19,770,172	(7,677,256)	1,342,276	(20,860,444)
Unrealized loss on natural gas liquid swaps	-	(650,285)	-	(940,557)
Unrealized gain (loss) on natural gas swaps	2,963,768	1,483,423	6,373,342	(2,586,381)
Total revenue	$ 36,048,955	$ 22,960,551	$ 48,799,696	$ 47,911,833
Expenses:				
Oil and natural gas production	$ 4,166,766	$ 7,580,473	$ 10,159,887	$ 18,408,152
Production and other taxes	$ 1,029,511	$ 1,886,122	$ 2,710,392	$ 4,360,881
General and administrative	$ 1,186,884	$ 1,443,190	$ 3,265,163	$ 6,039,371
Depletion, depreciation, amortization and accretion	$ 5,346,432	$ 6,959,351	$ 12,701,726	$ 19,065,064
Production:				
Oil - barrels	202,952	312,433	516,057	813,906
Natural gas liquids - gallons	-	1,344,553	-	2,303,892
Natural gas - Mcf	571,246	800,936	1,598,909	2,107,376
Total (Boe)	298,160	477,936	782,542	1,219,990
Average daily production (Boe/d)	3,241	5,195	2,866	4,469
Average sales price per unit (including hedges) (b):				
Oil price per barrel	$ 133.91	$ 44.55	$ 52.10	$ 38.99
Natural gas liquid price per gallon	$ -	$ 0.70	$ -	$ 0.78
Natural gas price per Mcf	$ 15.53	$ 10.11	$ 13.70	$ 6.83
Combined (per Boe)	$ 120.90	$ 48.04	$ 62.36	$ 39.27
Average sales price per unit (including realized hedge gains/losses) (c):				
Oil price per barrel	$ 36.49	$ 69.12	$ 49.50	$ 64.62
Natural gas liquid price per gallon	$ -	$ 1.19	$ -	$ 1.19
Natural gas price per Mcf	$ 10.34	$ 8.26	$ 9.72	$ 8.05
Combined (per Boe)	$ 44.66	$ 62.36	$ 52.50	$ 59.26
Average sales price per unit (excluding hedges):				
Oil price per barrel	$ 65.06	$ 71.83	$ 62.87	$ 63.15
Natural gas liquid price per gallon	$ -	$ 1.27	$ -	$ 1.25
Natural gas price per Mcf	$ 7.42	$ 6.54	$ 6.77	$ 6.54

Combined (per Boe)	$	58.50	$	61.51	$	55.29	$	55.79
NYMEX oil index prices per barrel:								
Beginning of Period	$	73.93	$	70.68	$	61.04	$	61.05
End of Period	$	62.91	$	81.66	$	62.91	$	81.66
NYMEX gas index prices per Mcf:								
Beginning of Period	$	6.10	$	6.77	$	11.18	$	6.30
End of Period	$	5.62	$	6.87	$	5.62	$	6.87
Average unit costs per Boe:								
Production costs, excluding production and other taxes	$	13.97	$	15.86	$	12.98	$	15.09
Production and other taxes	$	3.45	$	3.95	$	3.46	$	3.57
General and administrative	$	3.98	$	3.02	$	4.17	$	4.95
Depletion, depreciation, amortization and accretion	$	17.93	$	14.56	$	16.23	$	15.63

(a) Reflects the production and operating results of the oil and natural gas properties acquired in the March 15, 2006 formation transaction.

(b) Includes both the realized and unrealized hedge gains and losses from Legacy's oil and natural gas swaps. Since Legacy does not specifically designate its commodity derivative instruments as cash flow hedges, current earnings reflect a mark-to-market adjustment for commodity derivatives which will be settled in future periods.

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

Results of Operations

Three-Month Period Ended September 30, 2007 Compared to Three-Month Period Ended September 30, 2006

Legacy's revenues from the sale of oil were $22.4 million and $13.2 million for the three-month periods ended September 30, 2007 and 2006, respectively. Legacy's revenues from the sale of natural gas liquids were $1.7 million and $0 for the three-month periods ended September 30, 2007 and 2006, respectively. Legacy's revenues from the sale of natural gas were $5.2 million and $4.2 million for the three-month periods ended September 30, 2007 and 2006, respectively. The $9.2 million increase in oil revenues reflects an increase in oil production of 109 MBbls (54%) due primarily to the Binger, Ameristate, TSF, Raven Shenandoah and Raven OBO acquisitions and the increase in realized price excluding the effects of hedging of $6.77 per Bbl. The $1.7 million increase in natural gas liquids is due primarily to the Binger acquisition in 2007. The $1.0 million increase in natural gas revenues reflects an increase in natural gas production of approximately 230 MMcf (40%) due primarily to the Binger, Ameristate, TSF, Raven Shenandoah and Raven OBO acquisitions, while the realized price per Mcf excluding the effects of hedging decreased $0.88 per Mcf.

For the three-month period ended September 30, 2007, Legacy recorded $6.4 million of net losses on oil and natural gas swaps comprised of realized gains of $0.4 million from net cash settlements of oil and natural gas swap contracts and net unrealized losses of $6.8 million. Legacy had unrealized net losses from oil swaps because the fixed prices of its oil swap contracts were below the NYMEX index prices at September 30, 2007. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close at September 30, 2007 was $81.66 per Bbl, a price which is greater than the average contract prices of 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 increased, resulting in losses for the quarter. Legacy had unrealized net losses from natural gas liquids swaps because the fixed prices of its natural gas liquids swap contracts were below the NYMEX index prices at September 30, 2007. Legacy had unrealized net gains from natural gas swaps because the fixed prices of its natural gas swap contracts were above the NYMEX index prices at September 30, 2007. In addition, the NYMEX price for natural gas for the near-month close at September 30, 2007 was $6.87 per MMbtu, a price which is less than the average contract prices of Legacy's outstanding natural gas swap contracts. Due to the addition of natural gas swap contracts during the quarter at prices greater than the NYMEX natural gas price at September 30, 2007, the increase in natural gas prices during the quarter did not result in unrealized losses for the quarter. For the three-month period ended September 30, 2006, Legacy recorded $18.6 million of net gains on oil and natural gas swaps comprised of a realized loss of $5.8 million from net cash settlements of oil swap contracts, a realized gain of $1.7 million from net cash settlements of natural gas swap contracts, a net unrealized gain of $19.8 million on oil swap contracts, due to the decrease in oil prices during the quarter which increased the differential between the NYMEX oil index price and our fixed price oil swaps, and a net unrealized gain of $3.0 million on natural gas swap contracts, due to the decrease in natural gas prices which increased the differential between the NYMEX natural gas index price and our fixed price natural gas swaps. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods.

Legacy's oil and natural gas production expenses, excluding production and other taxes, increased to $7.6 million ($15.86 per Boe) for the three-month period ended September 30, 2007, from $4.2 million ($13.97 per Boe) for the three month period ended September 30, 2006. Production expenses increased primarily because of (i) $1.8 million related to the Binger, Ameristate, TSF, Raven Shenandoah and Raven OBO acquisitions, (ii) $0.3 million related to increases in ad valorem expenses from increased well counts and periods of ownership. In addition, the increase in production costs per Boe is consistent with industry-wide costs increases, particularly those related to oil operations that require lifting produced oil and water or involve enhanced recovery projects. Due to the rising oil and natural gas prices subsequent to September 30, 2007, Legacy believes production expenses could continue to rise in the fourth quarter, to the extent that production costs correlate to oil and natural gas prices.

Legacy's production and other taxes were $1.9 million and $1.0 million for the three-month periods ended September 30, 2007 and 2006, respectively. Production and other taxes increased primarily because of approximately $0.5 million of taxes related to the Binger, Ameristate, TSF Raven Shenandoah and Raven OBO acquisitions. The increase in production and other taxes per Boe is primarily due to the increase in realized prices excluding the effects of oil and natural gas swaps. As production and other taxes are a function of price and volume, the increase in cost per unit is consistent with the increase in realized prices.

Legacy's general and administrative expenses were $1.4 million and $1.2 million for the three-month periods ended September 30, 2007 and 2006, respectively. General and administrative expenses increased approximately $256,000 between periods primarily due to increased employee costs related to business expansion.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $6.9 million and $5.3 million for the three-month periods ended September 30, 2007 and 2006, respectively, reflecting primarily $1.7 million of DD&A related to recent acquisitions. In addition, the decrease in DD&A expense per Boe, from $17.93 to $14.56 for the three-month periods ended September 30, 2006 and 2007, respectively, reflects the higher cost basis of the producing oil and natural gas properties acquired in the Legacy Formation relative to the cost basis of recent acquisitions.

Impairment expense was $950,174 for the three-month period ended September 30, 2007 involving seventeen separate producing fields. The impairment is primarily due to additional costs incurred during the quarter ended September 30, 2007 on fields from which the future estimated production revenues did not exceed these costs. Impairment expense was $8.6 million for the three-month period ended September 30, 2006, involving 22 separate producing fields, due primarily to the decline in natural gas prices from the dates at which the purchase prices for the PITCO acquisition and the Legacy Formation were allocated among the purchased properties.

Legacy recorded interest income of $54,285 for the three-month period ended September 30, 2007 and $55,226 for the three-month period ended September 30, 2006. The decrease of $941 is a result of lower average cash balances for the current period.

Interest expense was $1.9 million for each of the three-month periods ended September 30, 2007 and 2006, reflecting lower average borrowings and higher average interest rates in the current period. For example, the average debt balance outstanding was $83 million and $98 million for the three month periods ended September 30, 2007 and 2006, respectively. In addition, Legacy incurred $275,000 in non-cash interest expense related to the mark-to-market of its interest rate swaps for the three-month period ended September 30, 2007.

Legacy recognized $29,690 in income from non-controlling interest of Binger Operations, LLC ("BOL") for the three-month period ended September 30, 2007. This income is primarily derived from BOL's less than 1% interest in the Binger Unit.

Nine-Month Period Ended September 30, 2007 Compared to Nine-Month Period Ended September 30, 2006

Legacy's revenues from the sale of oil were $51.4 million and $32.4 million for the nine-month periods ended September 30, 2007 and 2006, respectively. Legacy's revenues from the sale of natural gas liquids were $2.9 million for the nine-month period ended September 30, 2007. Legacy's revenues from the sale of natural gas were $13.8 million and $10.8 million for the nine-month periods ended September 30, 2007 and 2006, respectively. The $19.0 million increase in oil revenues reflects an increase in oil production of 298 MBbls (58%) due primarily to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, Kinder Morgan, Larron and South Justis acquisitions, and the increase in the realized price excluding the effects of hedging of $0.28 per Bbl. The $2.9 million in natural gas liquids is due primarily to the Binger acquisition in 2007. The $3.0 million increase in natural gas revenues reflects an increase in natural gas production of approximately 508 MMcf (32%) due primarily to the Binger, Ameristate, TSF, Raven OBO, Raven Shenandoah, Kinder Morgan, Larron and South Justis acquisitions, while the realized price per Mcf excluding the effects of hedging decreased $0.23 per Mcf.

For the nine-month period ended September 30, 2007, Legacy recorded $20.2 million of net losses on oil and natural gas swaps comprised of realized gains of $4.2 million from net cash settlements of oil, natural gas liquids and natural gas swap contracts and net unrealized losses of $24.4 million. Legacy had unrealized net losses from its oil swaps because the fixed prices of its oil swap contracts were below the NYMEX index prices at September 30, 2007. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close at September 30, 2007 was $81.66 per Bbl, a price which is greater than the average contract prices of Legacy's outstanding oil swap contracts. Due to the increase in oil prices during the nine-month period ended September 30, 2007, the differential between Legacy's fixed price oil swaps and NYMEX increased, resulting in unrealized losses for the nine-month period ended September 30, 2007. Legacy had unrealized net losses from its natural gas liquid swaps because the fixed prices of its natural gas liquid swap contracts during the nine-month period ended September 30, 2007, were below the NYMEX index prices during that timeframe. Legacy had unrealized net losses from its natural gas swaps because the fixed prices of its natural gas swap contracts during the nine-month period ended September 30, 2007 were below the NYMEX index prices during that timeframe. In addition, the NYMEX price for natural gas for the near-month close at September 30, 2007 was $6.87 per MMbtu, a price which is less than the average contract prices of Legacy's outstanding natural gas swap contracts. For the nine-month period ended September 30, 2006, Legacy recorded $5.5 million of net gains on oil and natural gas swaps comprised of a realized loss of $6.9 million from net cash settlements of oil swap contracts, a realized gain of $4.7 million from net cash settlements of natural gas swap contracts, a net unrealized gain of $1.3 million on oil swap contracts, due to the increase in oil prices during the nine-month period ended September 30, 2007 which increased the differential between the NYMEX oil index price and our fixed price oil swaps, and a net unrealized gain of $6.4 million on natural gas swap contracts, due to the decrease in natural gas prices which increased the differential between the NYMEX natural gas index price and our fixed price natural gas swaps. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods.

Legacy's oil and natural gas production expenses, excluding production and other taxes, increased to $18.4 million ($15.09 per Boe) for the nine-month period ended September 30, 2007, from $10.2 million ($12.98 per Boe) for the nine-month period ended September 30, 2006. Production expenses increased primarily because of (i) $2.8 million related to the Binger, Ameristate, TSF, Raven Shenandoah and Raven OBO acquisitions, (ii) $0.8 million related to increases in ad valorem expenses from increased well counts and periods of ownership, (iii) $1.3 million related to the Legacy Formation and (iv) $1.6 million related to the South Justis, Farmer Field and Kinder Morgan acquisitions. In addition, the increase in production costs per Boe is consistent with industry-wide costs increases, particularly those related to oil operations that require lifting produced oil and water or involve enhanced recovery projects. Due to the rising oil and natural gas prices subsequent to September 30, 2007, Legacy believes production expenses could continue to rise in the fourth quarter, to the extent that production costs correlate to oil and natural gas prices.

Legacy’s production and other taxes were $4.4 million and $2.7 million for the nine-month periods ended September 30, 2007 and 2006, respectively. Production and other taxes increased primarily because of approximately $0.3 million of taxes related to the Legacy Formation and $0.8 million related to the Binger, Ameristate, TSF, Raven Shenandoah and Raven OBO acquisitions. The increase in production and other taxes per Boe is primarily due to the increase in realized prices excluding hedges. As production and other taxes are a function of price and volume, the increase in unit cost is consistent with the increase in realized prices.

Legacy’s general and administrative expenses were $6.0 million and $3.3 million for the nine-month periods ended September 30, 2007 and 2006, respectively. General and administrative expenses increased approximately $2.7 million between periods primarily due to increased employee costs related to business expansion, $0.9 million of costs incurred in connection with awards granted under the LTIP due to a $0.6 million non-cash expense related to the change in estimated fair value of the unit-based compensation liability related to unit options and unit appreciation rights and $0.3 million of cash payments to employees exercising unit options and approximately $0.5 million of costs incurred in connection with the preparation of the 2006 federal income tax return and related Form K-1’s.

Legacy’s depletion, depreciation, amortization and accretion expense, or DD&A, was $19.1 million and $12.7 million for the nine-month periods ended September 30, 2007 and 2006, respectively, reflecting primarily (i) $2.7 million of DD&A related to the Binger, Ameristate, TSF, Raven Shenandoah and Raven OBO acquisitions, (ii) $1.1 million of DD&A related to the Legacy Formation and (iii) $1.6 million related to the South Justis, Farmer Field and Kinder Morgan acquisitions. In addition, the decrease in DD&A expense per Boe, from $16.23 to $15.63 for the nine-month periods ended September 30, 2006 and 2007, respectively, reflects the higher cost basis of the producing oil and natural gas properties acquired in the Legacy Formation relative to the cost basis of recent acquisitions.

Impairment expense was $1.2 million for the nine-month period ended September 30, 2007 involving thirty separate producing fields. The impairment is primarily due to additional costs incurred during the nine months ended September 30, 2007 on fields from which the future estimated production revenues did not exceed these costs. Impairment expense was $8.6 million for the nine-month period ended September 30, 2006, involving 22 separate producing fields, due primarily to the decline in natural gas prices from the dates at which the purchase prices for the PITCO acquisition and the Legacy Formation were allocated among the purchased properties.

Legacy recorded interest income of $205,443 for the nine-month period ended September 30, 2007 and $93,659 for the nine-month period ended September 30, 2006. The increase of $111,784 is a result of higher average cash balances in the current period.

Interest expense was $3.4 million and $4.5 million for the nine-month periods ended September 30, 2007 and 2006, respectively, reflecting lower average borrowings and higher average interest rates in the current period. For example, the average debt balance outstanding was $50.2 million and $59.6 million for the nine month periods ended September 30, 2007 and 2006, respectively. In addition, Legacy incurred $275,000 in non-cash interest expense related to the mark-to-market on its interest rate swaps for the nine-month period ended September 30, 2007.

Legacy recorded equity in loss of partnership of $317,788 for the nine-month period ended September 30, 2006. The recorded equity in loss of partnership was related to Legacy's investment in MBN Management, LLC, which was formed in July 2005. Legacy did not acquire any interest in MBN Management, LLC as part of the Legacy Formation. Accordingly, no such loss was incurred in the current period.

Legacy recognized $40,600 in income from non-controlling interest of BOL for the nine-month period ended September 30, 2007. This income is primarily derived from BOL's less than 1% interest in the Binger Unit.

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 and the IPO in January 2007. To date, Legacy's primary use of capital has been for acquisitions, repayment of bank borrowings and exploitation of oil and natural gas properties.

As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and exploiting additional reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our credit facility, if available, or obtain additional debt or equity financing. Our credit facility imposes certain restrictions on our ability to obtain additional debt financing. Based upon current oil and natural gas price expectations for the year ending December 31, 2007, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our credit facility will provide us sufficient working capital to meet our planned capital expenditures of $12.5 million and planned cash distributions of $40.4 million, which reflects the $7.6 million of distributions paid in the first quarter of 2007, $10.7 million paid in the second quarter of 2007, $10.9 million paid in the third quarter of 2007 and $11.2 million of planned distributions in the fourth quarter of 2007. Please read "— Financing Activities — Our Revolving Credit Facility."

On October 24, 2007, Legacy's bank group increased Legacy's borrowing base to $225 million as part of the Third Amendment to the Credit Agreement.

Cash Flow from Operations

Legacy's net cash provided by operating activities was $33.3 million and $21.8 million for the nine-month periods ended September 30, 2007 and 2006, respectively, with the 2007 period being favorably impacted by higher sales volumes, offset by the higher working capital needs of our growing business.

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 exploitation projects, as well as the prices of oil and natural gas.

We enter into oil and natural gas derivative contracts to reduce the impact of oil and natural gas price volatility on our operations. Currently, we use swaps, based on a NYMEX pricing index, to reduce our exposure to changes in oil, natural gas liquids and natural gas prices, which do not include the additional net discount that we typically experience in the Permian Basin. At September 30, 2007, we had in place oil, natural gas liquids and natural gas swaps covering significant portions of our estimated 2007 through 2011 oil and natural gas production. We have swap contracts covering approximately 77% of our remaining expected oil, natural gas liquid and natural gas production for 2007. We also have swap contracts covering approximately 67% of our currently expected oil and natural gas production for 2008 through 2010 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.

The following tables summarize, for the periods indicated, our oil and natural gas swaps currently in place through December 31, 2012. We use swaps 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 NYMEX price of oil at Cushing, Oklahoma, and NYMEX price of natural gas at Henry Hub and ANR-OK on the average of the three final trading days of the month and settlement occurs on the fifth day of the production month.

Calendar Year	Annual Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2007	273,578	$ 68.81	$64.15 - $75.70
2008	1,025,249	$ 68.57	$62.25 - $73.45
2009	948,013	$ 66.65	$61.05 - $71.40
2010	883,445	$ 65.26	$60.15 - $71.15
2011	665,040	$ 70.17	$67.33 - $71.40
2012	549,600	$ 70.04	$67.72 - $71.15

Calendar Year	Annual Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2007	656,192	$ 8.59	$6.85 - $10.01
2008	2,402,970	$ 8.17	$6.85 - $10.58
2009	2,217,470	$ 8.01	$6.85 - $10.18
2010	1,962,755	$ 7.74	$6.85 - $9.73
2011	694,024	$ 7.21	$6.85 - $7.51
2012	404,436	$ 7.07	$6.85 - $7.30

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

Calendar Year	Annual Volumes (Mcf)	Basis Differential per Mcf
2007	390,000	($0.88)
2008	1,422,000	($0.84)
2009	1,320,000	($0.68)
2010	1,200,000	($0.57)

On March 30, 2007, we entered into natural gas liquids swaps to hedge the impact of volatility in the spot prices of natural gas liquids. On September 7, 2007, we entered into additional natural gas liquids swaps for the fourth quarter of 2007 and calendar year 2008. 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. We entered into these swaps as anticipatory asset hedges related to our acquisition of the East Binger (Marchand) Unit in Caddo County, Oklahoma. The following table summarizes, for the periods indicated, our Mont Belvieu, Non-Tet Opis natural gas liquids swaps currently in place through December 31, 2009.

Annual	Average	Price

Calendar Year	Volumes (Gal)	Price per Gal	Range per Gal
2007	1,682,838	$ 1.32	$0.79 - $1.68
2008	6,458,004	$ 1.27	$0.66 - $1.62
2009	2,265,480	$ 1.15	$1.15

Investing Activities — Acquisitions and Capital Expenditures

Legacy's cash capital expenditures were $98.3 million for the nine-month period ended September 30, 2007. The total includes $88.0 million for acquisition of oil and natural gas properties in five acquisitions and $10.3 million of exploitation projects.

Legacy's cash capital expenditures were $45.4 million for the nine-month period ended September 30, 2006. The total includes $7.7 million paid to three charitable foundations in the Legacy Formation for oil and natural gas properties, $8.8 million, $5.6 million and $17.2 million for the purchase of oil and natural gas properties in the South Justis Unit from Henry Holding LP, the Farmer Field from Larron Oil Corporation and various oil and natural gas properties from Kinder Morgan, respectively, and $7.0 million of capitalized operating rights related to the South Justis Unit.

We currently anticipate that our drilling budget, which predominantly consists of drilling, recompletion and refracture stimulation projects and one tertiary (CO_2) recovery project, will be $12.5 million for the year ending December 31, 2007. Our borrowing capacity under our revolving credit facility is $59.7 million as of November 9, 2007. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. If oil and natural gas prices decline below levels we deem acceptable, we may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews. Based upon current oil and natural gas price expectations for the year ending December 31, 2007, 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 $12.5 million and planned cash distributions of $40.4 million for the year ending December 31, 2007. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Initial Public Offering

On January 18, 2007, Legacy completed its IPO of 6,900,000 units at an IPO price of $19.00 per unit. Net proceeds to Legacy after underwriting discounts and estimated offering expenses were approximately $122 million, all of which were used to repay in full the indebtedness outstanding under Legacy's credit facility and for general partnership purposes.

Our Revolving Credit Facility

At the closing of our private equity offering on March 15, 2006, we entered into a new, four-year, $300 million revolving credit facility with BNP Paribas as administrative agent. On October 24, 2007, the maximum credit amount was increased to $500 million as part of the Third Amendment to the credit agreement. Our obligations under the credit facility are secured by mortgages on more than 80% of our oil and gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base, which was initially set at $130 million and was increased on October 24, 2007 to $225 million. The borrowing base is subject to semi-annual re-determinations on April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to re-determine the borrowing base between scheduled re-determinations. We also have the right, once during each calendar year, to re-determine the borrowing base upon the proposed acquisition of certain oil and gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders and any decrease in the borrowing base must be approved by the lenders holding 66 2/3 % of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66 2/3 % of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the credit facility so long as it does not increase the borrowing base then in effect. Outstanding borrowings in excess of the borrowing base must be prepaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral.

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

- with respect to ABR loans, the alternate base rate equals the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.250%, or
- with respect to any Eurodollar loans for any interest period, the London interbank rate, or LIBOR plus an applicable margin between 1.00% and 1.75% per annum.

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

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

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

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

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

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

- failure to pay any principal when due or any reimbursement amount, interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants or conditions contained in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $1.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or any of our subsidiaries;

- the loan documents cease to be in full force and effect as a result of our failing to create a valid lien, except in limited circumstances;
- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of March 15, 2006 and persons who are nominated for election or elected to our general partner's board of directors with the approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) Legacy Reserves GP, LLC ceasing to be our sole general partner;
- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and
- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1,000,000 in any year.

At September 30, 2007, Legacy was in compliance with all financial and other covenants of the Legacy Facility.

Legacy entered into a Unit Purchase Agreement (the "Purchase Agreement"), dated effective as of November 7, 2007, with Legacy Reserves GP, LLC and certain institutional investors (the "Purchasers") to sell an aggregate of 3,642,369 units representing limited partner interests in LRLP (the "Units") in a private placement (the "Private Placement"). The negotiated purchase price for the Units in the Purchase Agreement was $20.50 per unit, or approximately $75 million in the aggregate.

The Private Placement closed, and 3,642,369 Units were issued, on November 8, 2007. LRLP will use the net proceeds from the Private Placement primarily to reduce debt currently outstanding under the Legacy Facility. The borrowings were used to finance the acquisition of properties in the Texas Panhandle and Permian Basin which closed during October 2007 for approximately $74 million. The Private Placement pursuant to the Purchase Agreement is being made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof.

In connection with the Purchase Agreement, LRLP also entered into a Registration Rights Agreement dated November 8, 2007 (the "Registration Rights Agreement") with the Purchasers. The Registration Rights Agreement requires LRLP to file a shelf registration statement with the Securities and Exchange Commission ("SEC") to register the Units as soon as practicable after the closing date of the Private Placement, but in any event within 90 days after the closing, which occurred on November 8, 2007. In addition, the Registration Rights Agreement requires LRLP to use its commercially reasonable efforts to cause the shelf registration statement to become effective no later than 180 days after the closing date of the Private Placement (the "Target Effective Date"). If the registration statement covering the Units is not declared effective by the SEC within 180 days after the closing date of the Private Placement (the "Target Effective Date"), then LRLP will be liable to each Purchaser for liquidated damages, and not as a penalty, of 0.25% of the product of $20.50 (the purchase price) times the number of Units purchased by the Purchaser (the "Liquidated Damages Amount") per the 30-day period for the first 30 days following the Target Effective Date, increasing by an additional 0.25% of the Liquidated Damages Amount per each non-overlapping 30-day period for each subsequent 30-day period subsequent to the 30 days following the Target Effective Date, up to a maximum of 1.00% of the Liquidated Damages Amount per each non-overlapping 30-day period (i.e., 0.25% for 1-30 days; 0.5% for 31-60 days; 0.75% for 61-90 days; and 1.0% thereafter); *provided*, that the aggregate amount of liquidated damages payable by LRLP under the Registration Rights Agreement to each Purchaser shall not exceed 10.0% of the Liquidated Damages Amount with respect to such Purchaser. The Registration Rights Agreement also provides for the payment of liquidated damages in the event LRLP suspends the use of the shelf registration statement in excess of permitted periods. The Registration Rights Agreement also gives certain Purchasers piggyback registration rights with other shelf registration statements under certain circumstances.

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 consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Estimates and assumptions are evaluated on a regular basis. Legacy based its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making

judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

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

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

Nature of Critical Estimate Item: Oil and Natural Gas Reserves — Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. LaRoche Petroleum Consultants, Ltd., 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 September 30, 2007 by approximately 10%.

Nature of Critical Estimate Item: Asset Retirement Obligations — We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. We adopted Statement of Financial Accounting Standards ("SFAS") No. 143, Accounting for Asset Retirement Obligations effective January 1, 2003. SFAS No. 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets ("asset retirement obligations" or "ARO"). Primarily, SFAS No. 143 requires us to estimate asset retirement costs for all of our assets, adjust those costs for inflation to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an ARO liability in that amount with a corresponding addition to our asset value. When new obligations are incurred, i.e. a new well is drilled or acquired, we add a layer to the ARO liability. We then accrete the liability layers quarterly using the applicable period-end effective credit-adjusted-risk-free rates for each layer. Should either the estimated life or the estimated abandonment costs of a property change materially upon our quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the 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 some significant calculations, could differ from actual results, despite our efforts to make an accurate estimate. We engage independent engineering firms to evaluate our properties annually. We use the remaining estimated useful life from the year-end reserve report by our independent reserve engineers in estimating when abandonment could be expected for each property. 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 and natural gas production by reducing our exposure to price fluctuations. Currently, these transactions are swaps whereby we exchange our floating price for our oil and natural gas for a fixed price with qualified and creditworthy counterparties (currently BNP Paribas, Bank of America, Key Bank and Wachovia). Our existing oil and natural gas swaps are with members of our lending group which enables us to avoid margin calls for out-of-the money mark-to-market positions.

We do not specifically designate derivative instruments as cash flow hedges, even though they reduce our exposure to changes in oil and natural gas prices. Therefore, the mark-to-market adjustments of these instruments is recorded in current earnings. While we are not internally preparing an estimate of the current market value of these derivative instruments, we use market value statements from each of our counterparties as the basis for these end-of-period mark-to-market adjustments. When we record a mark-to-market adjustment resulting in a loss in a current period, these unrealized losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. As shown in the tables above, we have hedged a significant portion of our future production through 2011. As oil and natural gas prices rise and fall, our future cash obligations related to these derivatives will rise and fall.

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

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

As of September 30, 2007, the fair market value of Legacy's derivative positions was a net liability of $21.6 million. As of December 31, 2006, the fair market value of Legacy's derivative positions was an asset of $3.1 million. The oil and natural gas swaps for 2007 through December 31, 2012 are tabulated in the tables presented above under "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow from Operations."

At September 30, 2007, we have oil swaps in place covering future oil production of approximately 4.3 million barrels. Subsequent to September 30, 2007, oil futures prices have increased significantly. These increases in oil price futures will require us to make larger net settlement payments under commodity swap contracts. While these payments should not significantly affect our cash flow since payments made to counterparties to these contracts should be more than offset by increased commodity prices received on the sale of our production (some of which is unhedged), the increase in oil prices, should they continue, will negatively affect the fair value of our commodities contracts as recorded in our balance sheet at December 31, 2007 and during future periods and, consequently, our reported net earnings. Changes in the recorded fair value of commodity derivatives are marked to market through earnings and are likely to result in substantial charges to earnings for the decrease in the fair value of these contracts during the fourth quarter of 2007. If oil prices continue to increase, this negative effect on earnings will become more significant. We are currently unable to estimate the effects on earning s the fourth quarter of 2007, but the effects may be substantial.

Interest Rate Risks

At September 30, 2007, Legacy had debt outstanding of $93.0 million, which incurred interest at floating rates in accordance with its revolving credit facility and the subordinated notes payable. The average annual interest rate incurred by Legacy for the nine-month period ended September 30, 2007 was 8.02%. A 1% increase in LIBOR on Legacy's outstanding debt as of September 30, 2007 would result in an estimated $390,000 increase in annual interest expense. Legacy has entered into interest rate derivative transactions to mitigate its interest rate risk on $54 million of its outstanding debt balance by exchanging floating rates for fixed rates ranging from 4.8075% to 4.82%.

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 September 30, 2007. Based upon that evaluation and subject to the foregoing, our General Partner’s Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

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

There have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended September 30, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1A. ***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***

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, 2006, 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, 2006 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.

On April 16, 2007, we issued 611,247 units in consideration for our acquisition of producing oil and natural gas properties in the East Binger (Marchand) Unit in Caddo County, Oklahoma. The issuance of these units was exempt from registration under Section 4(2) of the Securities Act.

Issuer Purchases of Equity Securities

Period	**(a) Total Number of Units Purchased**	**(b) Average Price Paid per Unit**	**(c) Total Number of Units Purchased as Part of Publicly Announced Plans or Programs**	**(d) Maximum Number (or Approximate Dollar Value) of Units that May Yet Be Purchased Under the Plans or Programs**
April 2007	17,256	$28.01	-	-
May 2007	5,782	$27.96	-	-
Total	23,038	$28.00	-	-

On April 11, 2007, employees of Legacy exercised 17,256 vested unit options granted under the Legacy Reserves LP LTIP at an exercised price of $17.00 per unit and immediately following such exercise transferred the units received upon such exercise to Legacy in exchange for a payment by Legacy of $28.01 per unit, the closing price of Legacy's units on the NASDAQ Global Market on such date.

On May 17, 2007, employees of Legacy exercised 4,008 vested unit options granted under the Legacy Reserves LP LTIP at an exercised price of $17.00 per unit and immediately following such exercise transferred the units received upon such exercise to Legacy in exchange for a payment by Legacy of $28.00 per unit, the closing price of Legacy's units on the NASDAQ Global Market on such date.

On May 18, 2007, employees of Legacy exercised 904 vested unit options granted under the Legacy Reserves LP LTIP at an exercised price of $17.00 per unit and immediately following such exercise transferred the units received upon such exercise to Legacy in exchange for a payment by Legacy of $27.92 per unit, the closing price of Legacy's units on the NASDAQ Global Market on such date.

On May 22, 2007, employees of Legacy exercised 870 vested unit options granted under the Legacy Reserves LP LTIP at an exercised price of $17.00 per unit and immediately following such exercise transferred the units received upon such exercise to Legacy in exchange for a payment by Legacy of $27.84 per unit, the closing price of Legacy's units on the NASDAQ Global Market on such date.

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 Reserve LP's Registration Statement on Form S-1 (File No. 33-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	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)
3.4	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
4.1	Registration Rights Agreement dated as of March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and Friedman, Billings, Ramsey & Co. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 4.1)
4.2	Registration Rights Agreement dated June 29, 2006 between Henry 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)
4.3	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)
4.4	Registration Rights Agreement dated April 16, 2007 by and among Nielson & Associates, Inc., Legacy Reserves GP, LLC and Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP Quarterly Report on Form 10-Q (File No. 001-33249) filed May 14, 2007, Exhibit 4.4)
10.1*	Purchase, Sale and Contribution Agreement dated July 11, 2007, by and among Raven Resources, LLC and Legacy Reserves Operating LP
10.2	Amended and Restated Legacy Reserves LP Long-Term Incentive Plan (Incorporated by reference to Legacy Reserves LP Current Report on Form 8-K (File No. 001-33249) filed August 23, 2007, Exhibit 10.1)
10.3*	Purchase, Sale and Contribution Agreement dated August 28, 2007, by and among Summit Petroleum Management Corporation and Legacy Reserves Operating LP
10.4*	Purchase, Sale and Contribution Agreement dated August 30, 2007, by and among The Operating Company and Legacy Reserves Operating LP
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