LEGACY RESERVES LP
Form 10-Q
August 08, 2008

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 June 30, 2008

OR

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

SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number 1-33249

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

x Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer o

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

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

31,061,839 units representing limited partner interests in the registrant were outstanding as of August 8, 2008.

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GLOSSARY OF TERMS

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

Bcf. Billion cubic feet.

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

Boe/d. Barrels of oil equivalent per day.

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

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

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

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

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

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

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

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

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

Mcf. One thousand cubic feet.

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

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

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

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

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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

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

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

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

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

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

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

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

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

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

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

	June 30, 2008	December 31, 2007
	(Dollars in thousands)	
Current assets:		
Cash and cash equivalents	$ 7,237	$ 9,604
Accounts receivable, net:		
Oil and natural gas	30,624	19,025
Joint interest owners	4,850	4,253
Affiliated entities and other (Note 4)	55	26
Fair value of derivatives (Notes 6 and 7)	20	310
Prepaid expenses and other current assets	3,376	340
Total current assets	46,162	33,558
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, at cost, using the successful efforts method of accounting:	663,136	512,396
Unproved properties	78	78
Accumulated depletion, depreciation and amortization	(90,289)	(72,294)
	572,925	440,180
Other property and equipment, net of accumulated depreciaton and amortization of $452 and $251, respectively	1,847	775
Operating rights, net of amortization of $1,145 and $865, respectively	5,872	6,151
Fair value of derivatives (Notes 6 and 7)	1,676	-
Other assets, net of amortization of $613 and $391, respectively	1,076	822
Investment in equity method investee (Note 3)	92	92
Total assets	$ 629,650	$ 481,578

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

LIABILITIES AND UNITHOLDERS' EQUITY

		June 30, 2008		December 31, 2007
		(Dollars in thousands)		
Current liabilities:				
Accounts payable	$	1,304	$	2,320
Accrued oil and natural gas liabilities		17,572		10,102
Fair value of derivatives (Notes 6 and 7)		100,684		26,761
Asset retirement obligation (Note 8)		1,333		845
Other (Note 9)		5,028		3,429
Total current liabilities		125,921		43,457
Long-term debt (Note 2)		206,000		110,000
Asset retirement obligation (Note 8)		21,411		15,075
Fair value of derivatives (Notes 6 and 7)		218,714		57,316
Other long-term liabilites		171		-
Total liabilities		572,217		225,848
Commitments and contingencies (Note 5)				
Unitholders' equity:				
Limited partners' equity - 31,036,799 and 29,670,887 units issued and outstanding at June 30, 2008 and December 31, 2007, respectively		57,500		255,663
General partner's equity (approximately 0.1%)		(67)		67
Total unitholders' equity		57,433		255,730
Total liabilities and unitholders' equity	$	629,650	$	481,578

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 48,439	$ 16,654	$ 84,488	$ 28,954
Natural gas liquid sales	4,781	1,072	8,283	1,177
Natural gas sales	13,389	5,010	22,625	8,536
Total revenues	66,609	22,736	115,396	38,667
Expenses:				
Oil and natural gas production	13,515	6,088	23,042	10,828
Production and other taxes	4,089	1,481	6,558	2,475
General and administrative	3,696	2,769	6,714	4,595
Depletion, depreciation, amortization and accretion	10,523	6,811	20,140	12,106
Impairment of long-lived assets	4	190	108	280
Loss on disposal of assets	26	231	75	231
Total expenses	31,853	17,570	56,637	30,515
Operating income	34,756	5,166	58,759	8,152
Other income (expense):				
Interest income	15	47	71	151
Interest expense (Notes 2, 6 and 7)	1,212	(893)	(2,966)	(1,518)
Equity in income of partnerships	45	11	87	11
Realized gain (loss) on oil, NGL and natural gas swaps	(15,142)	1,362	(21,908)	3,827
Unrealized loss on oil, NGL and natural gas swaps (Notes 6 and 7)	(201,326)	(7,855)	(235,352)	(17,543)
Other	(3)	-	(19)	1
Loss before income taxes	(180,443)	(2,162)	(201,328)	(6,919)
Income taxes	(297)	-	(507)	-
Loss from continuing operations	(180,740)	(2,162)	(201,835)	(6,919)
Gain on sale of discontinued operation (Note 3)	4,954	-	4,954	-
Net loss	$ (175,786)	$ (2,162)	$ (196,881)	$ (6,919)
Loss from continuing operations per unit - basic and diluted	$ (5.90)	$ (0.08)	$ (6.70)	$ (0.27)
Gain on discontinued operation per unit - basic and diluted	$ 0.16	$ -	$ 0.16	$ -
Net loss per unit - basic and diluted	$ (5.74)	$ (0.08)	$ (6.53)	$ (0.27)

Weighted average number of units used in computing				
net loss per unit - basic and diluted	30,608	25,920	30,141	25,224

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENT OF UNITHOLDERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2008
(UNAUDITED)

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders' Equity
		(In thousands)		
Balance, December 31, 2007	29,671	$ 255,663	$ 67	$ 255,730
Costs associated with private placement equity offering in prior period	-	(6)	-	(6)
Units issued to Legacy Board of Directors for services	1	12	-	12
Compensation expense on restricted unit awards issued to employees	-	170	-	170
Vesting of restricted units	20	-	-	-
Units issued in COP III acquisition	1,345	27,000	-	27,000
Distributions to unitholders, $0.94 per unit	-	(28,575)	(17)	(28,592)
Net loss	-	(196,764)	(117)	(196,881)
Balance, June 30, 2008	31,037	$ 57,500	$ (67)	$ 57,433

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Dollars in thousands)	
Cash flows from operating activities:		
Net loss	$ (196,881)	$ (6,919)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	20,140	12,106
Amortization of debt issuance costs	222	84
Impairment of long-lived assets	108	280
Loss on derivatives	255,843	13,716
Equity in income of partnership	(87)	(11)
Amortization of unit-based compensation	1,393	55
(Gain) loss on disposal of assets	(4,879)	231
Changes in assets and liabilities:		
Increase in accounts receivable, oil and natural gas	(11,599)	(1,817)
Increase in accounts receivable, joint interest owners	(597)	(1,111)
(Increase) decrease in accounts receivable, other	(29)	12
Increase in other current assets	(3,036)	(1,068)
Decrease in accounts payable	(1,016)	(2,238)
Increase in accrued oil and natural gas liabilities	7,470	791
Increase in other liabilities	349	868
Total adjustments	264,282	21,898
Net cash provided by operating activities	67,401	14,979
Cash flows from investing activities:		
Investment in oil and natural gas properties	(113,600)	(69,758)
Increase in deposit on pending acquisition	-	(13)
Investment in other equipment	(1,274)	(287)
Net cash settlements on oil and natural gas swaps	(21,908)	3,827
Investment in equity method investee	87	(73)
Net cash used in investing activities	(136,695)	(66,304)
Cash flows from financing activities:		
Proceeds from long-term debt	134,000	71,000
Payments of long-term debt	(38,000)	(118,800)
Payments of debt issuance costs	(475)	(106)
Proceeds (costs) from issuance of units, net	(6)	121,554
Distributions to unitholders	(28,592)	(18,256)
Net cash provided by financing activities	66,927	55,392
Net increase (decrease) in cash and cash equivalents	(2,367)	4,067
Cash and cash equivalents, beginning of period	9,604	1,062
Cash and cash equivalents, end of period	$ 7,237	$ 5,129
Non-Cash Investing and Financing Activities:		

Asset retirement obligations associated with property acquisitions	$	6,770	$	727
Units issued in exchange for oil and natural gas properties	$	27,000	$	18,022
Non-cash exchange of oil and gas properties				
Properties received in exchange	$	7,746	$	-
Properties delivered in exchange	$	(3,122)	$	-

See accompanying notes to condensed consolidated financial statements.

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

(1) Summary of Significant Accounting Policies

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

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

Certain information and footnote disclosures normally included in the financial statements prepared in accordance with generally accepted accounting principles in the United States ("GAAP") have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission. These condensed consolidated financial statements should be read in connection with the consolidated financial statements and notes thereto included in the Partnership's Annual Report on Form 10-K and 10-K/A for the year ended December 31, 2007.

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

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

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

• No limited partner shall have any management power over LRLP's business and affairs; the general partner shall conduct, direct and manage LRLP's activities.

• The general partner may be removed if such removal is approved by the unitholders holding at least 66 2/3 percent of the outstanding units, including units held by LRLP's general partner and its affiliates provided that a unit majority has elected a successor general partner.

• Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

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

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

The accompanying condensed consolidated financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred. These condensed consolidated financial statements as of June 30, 2008 and for the three and six months ended June 30, 2008 and 2007 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 six months ended June 30, 2008 and 2007.

(b) Recently Issued Accounting Pronouncements

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements. Statement No. 157 defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in GAAP and expands disclosure related to the use of fair value measures in financial statements. We adopted the statement effective January 1, 2008 and the adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows. See Note 6 for other disclosures required by Statement No. 157.

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

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 160, Non-controlling Interest in Consolidated Financial Statements – an amendment of ARB No. 51 ("SFAS 160"). SFAS 160 requires that accounting and reporting for minority interests will be re-characterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008, which will be the Partnership's fiscal year 2009. Based upon the June 30, 2008 balance sheet, the statement would have no impact.

(2) Credit Facility

As an integral part of the formation of Legacy, Legacy entered into a credit agreement with a senior credit facility (the "Legacy Facility"). Legacy has oil and natural gas properties pledged as collateral for borrowings under the Legacy Facility. The initial terms of the Legacy Facility permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $300 million. The borrowing base under the Legacy Facility, currently at $320 million, was initially set at $130 million. Pursuant to the Fourth Amendment to the credit agreement, the borrowing base was initially increased to $272 million as of April 24, 2008 and further increased to $320 million coincident with the closing of the COP III Acquisition, which closed on April 30, 2008. The borrowing base 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. Under the Legacy Facility, as amended, interest on debt outstanding is charged based on Legacy's selection of a LIBOR rate plus 1.25% to 1.875%, 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%.

As of June 30, 2008, Legacy had outstanding borrowings of $206 million at a weighted average interest rate of 4.21%. Legacy had approximately $113.7 million of availability remaining under the Legacy Facility as of June 30, 2008. For the three-month and six-month periods ended June 30, 2008, Legacy paid $1.8 million and $3.7 million of interest expense on the Legacy Facility, respectively. The Legacy Facility contains certain loan covenants requiring minimum financial ratio coverages, including the current ratio and EBITDA to interest expense. At June 30, 2008, Legacy was in compliance with all aspects of the Legacy Facility.

Long-term debt consists of the following at June 30, 2008 and December 31, 2007:

	June 30, 2008	December 31, 2007
	(Dollars in thousands)	
Legacy Facility- due March 2010	$ 206,000	$ 110,000

(3) Acquisitions

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 operating results from 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 operating results from 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 operating results from 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 operating results from these Raven Shenandoah Acquisition properties have been included from their acquisition on May 31, 2007.

Raven OBO Acquisition

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

TOC Acquisition

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

Summit Acquisition

Also on October 1, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Summit Petroleum Management Corporation for a net purchase price of $13.4 million (“Summit Acquisition”). The effective date of this purchase was September 1, 2007. The $13.4 million purchase price was allocated with $2.1

million recorded as lease and well equipment and $11.3 million as leasehold cost. Asset retirement obligations of $128,705 were recorded in connection with this acquisition. The operating results from these Summit Acquisition properties have been included from their acquisition on October 1, 2007.

COP III Acquisition

On April 30, 2008, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin and to a lesser degree in Oklahoma and Kansas from a third party for a net purchase price of $78.5 million. The purchase price was paid with the issuance of 1,345,291 newly issued units valued at $27.0 million and $51.5 million paid in cash ("COP III Acquisition"). The effective date of this purchase was January 1, 2008. The $78.5 million purchase price was allocated with $19.5 million recorded as lease and well equipment and $59.0 million as leasehold cost. Asset retirement obligations of $4.0 million were recorded in connection with this acquisition. The operating results from these COP III Acquisition properties have been included from their acquisition on April 30, 2008.

Reeves Unit Exchange

On May 2, 2008, Legacy entered into a non-monetary exchange with Devon Energy in which Legacy exchanged its 12.9% non-operated working interest in the Reeves Unit for a 60% interest in two operated properties. Prior to the exchange, Legacy's basis in the Reeves Unit was $4.4 million offset by $1.3 million of accumulated depletion. In addition, Legacy had asset retirement obligations of $0.3 million related to the Reeves Unit. Due to the commercial substance of the transaction, the excess fair value of $4.9 million above the carrying value of the Reeves Unit was recorded as a gain on sale of discontinued operation in the period ended June 30, 2008. Due to immateriality, we have not reflected the operating results of the Reeves Unit separately as a discontinued operation for any of the periods presented.

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions had each occurred on January 1 of the respective year. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)			
Revenues	$ 68,857	$ 34,282	$ 122,641	$ 63,595
Net loss	$ (175,086)	$ (410)	$ (194,951)	$ (4,409)
Loss per unit - basic and diluted:	$ (5.64)	$ (0.01)	$ (6.28)	$ (0.16)
Units used in computing loss per unit:				
basic and diluted	31,037	27,366	31,028	26,924

(4) Related Party Transactions

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

Legacy uses Lynch, Chappell and Alsup for legal services. Alan Brown, brother of Cary D. Brown, is a less than ten percent shareholder in this firm. Legacy paid legal fees to Lynch, Chappell and Alsup of $49,308 and $32,661 for the six months ended June 30, 2007 and 2008, respectively.

(5) Commitments and Contingencies

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

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

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

(6) Fair Value Measurements

We adopted SFAS No. 157, Fair Value Measurements, effective January 1, 2008 for financial assets and liabilities measured at fair value on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In February 2008, the FASB issued FSP No. 157-2, which delayed the effective date of SFAS No. 157 by one year for non-financial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

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

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

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

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes the valuation of our investments and financial instruments by SFAS No. 157 pricing levels as of June 30, 2008:

	Fair Value Measurements at June 30, 2008 Using			
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of June 30, 2008
	(Dollars in thousands)			
Oil, NGL and natural gas derivative swaps	$ -	$ (294,492)	$ (22,394)	$ (316,886)
Oil collars	-	-	(737)	(737)
Interest rate swaps	-	(79)	-	(79)
Total	$ -	$ (294,571)	$ (23,131)	$ (317,702)

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

Significant

		Unobservable Inputs (Level 3)		
		Three Months Ended June 30, 2008		Six Months Ended June 30, 2008
		(Dollars in thousands)		
Beginning balance	$	(7,849)	$	(4,502)
Total gains or (losses)		(16,860)		(20,952)
Settlements		1,578		2,323
Transfers in and/or out of level 3		-		-
Balance as of June 30, 2008	$	(23,131)	$	(23,131)
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of June 30, 2008	$	(15,282)	$	(18,629)

(7) Derivative Financial Instruments

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

All of these price risk management transactions are considered derivative instruments and accounted for in accordance with Statement of Financial Accounting Standards (“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 earnings for the period ended June 30, 2008.

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

For the three and six months ended June 30, 2007 and 2008, Legacy recognized realized and unrealized gains and losses related to its oil, NGL and natural gas derivatives. The impact on net loss from derivative activities was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Dollars in thousands)			
Crude oil derivative contract settlements	$ (12,595)	$ 843	$ (19,173)	$ 2,045
Natural gas liquid derivative contract settlements	(1,012)	(41)	(1,733)	(42)
Natural gas derivative contract settlements	(1,535)	560	(1,002)	1,824
Total derivative contract settlements	(15,142)	1,362	(21,908)	3,827
Unrealized change in fair value - oil contracts	(179,302)	(8,096)	(204,578)	(13,183)
Unrealized change in fair value - natural gas liquid contracts	(2,571)	(290)	(2,583)	(290)
Unrealized change in fair value - natural gas contracts	(19,453)	531	(28,191)	(4,070)
Total unrealized change in fair value	(201,326)	(7,855)	(235,352)	(17,543)
Total effect of derivative contracts	$ (216,468)	$ (6,493)	$ (257,260)	$ (13,716)

As of June 30, 2008, Legacy had the following NYMEX West Texas Intermediate crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July - December 2008	646,579	$ 74.19	$62.25 - $101.47
2009	1,197,613	$ 72.67	$61.05 - $101.47
2010	1,115,045	$ 71.54	$60.15 - $101.47
2011	879,840	$ 76.36	$67.33 - $101.47
2012	750,000	$ 76.85	$67.72 - $101.47

On June 24, 2008, Legacy entered into a NYMEX West Texas Intermediate crude oil derivative collar contract that combines a put option or “floor” with a call option or “ceiling”. The following table summarizes the contract as of June 30, 2008:

	Average	Average

Calendar Year	Volumes (Bbls)	Floor	Ceiling
2009	75,400	$ 120.00	$ 156.30
2010	71,800	$ 120.00	$ 156.30
2011	68,300	$ 120.00	$ 156.30
2012	65,100	$ 120.00	$ 156.30

As of June 30, 2008, Legacy had the following NYMEX Henry Hub, ANR-OK and Waha natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
July - December 2008	1,589,437	$ 8.05	$6.85 - $9.10
2009	2,924,042	$ 8.06	$6.85 - $10.18
2010	2,610,359	$ 7.85	$6.85 - $9.73
2011	1,908,616	$ 8.00	$6.85 - $8.70
2012	1,371,036	$ 8.01	$6.85 - $8.70

As of June 30, 2008, Legacy had the following natural gas basis swaps in which it receives floating NYMEX prices less a fixed basis differential and pays prices on the floating Waha index, a natural gas hub in West Texas. The prices that Legacy receives for its natural gas sales in the Permian Basin follow Waha more closely than NYMEX:

Calendar Year	Volumes (MMBtu)	Basis Range per Mcf
July - December 2008	711,000	($0.84)
2009	1,320,000	($0.68)
2010	1,200,000	($0.57)

As of June 30, 2008, Legacy had the following Mont Belvieu, Non-Tet OPIS natural gas liquids swaps paying floating natural gas liquids prices and receiving fixed prices for a portion of its future natural gas liquids production as indicated below:

Calendar Year	Volumes (Gal)	Average Price per Gal		Price Range per Gal
July - December 2008	3,145,380	$	1.28	$0.66 - $1.62
2009	2,265,480	$	1.15	$1.15

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

On March 14, 2008, Legacy entered into a LIBOR interest rate swap beginning in April of 2008 and extending through April of 2011. The swap transaction has Legacy paying its counterparty a fixed rate of 2.68% per annum, and receiving floating rates on a notional amount of $60 million. The swap is settled on a quarterly basis, beginning in July of 2008 and ending in April of 2011.

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

As the term of Legacy’s interest rate swaps extends through November of 2011, a period that extends beyond the term of the Legacy Facility, 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. The table below summarizes the interest rate swap position as of June 30, 2008.

Notional Amount		Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at June 30, 2008	
			(Dollars in thousands)			
$	29,000	4.8200%	10/16/2007	10/16/2011	$	(984)
$	13,000	4.8100%	11/16/2007	11/16/2011		(414)
$	12,000	4.8075%	11/28/2007	11/28/2011		(376)
$	60,000	2.6800%	4/1/2008	4/1/2011		1,695
					$	(79)

Total Fair Market Value	

(8) Asset Retirement Obligation

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, 2007 and six months ended June 30, 2008.

	June 30, 2008	December 31, 2007
	(Dollars in thousands)	
Asset retirement obligation - beginning of period	$ 15,920	$ 6,493
Liabilities incurred with properties acquired	6,770	3,033
Liabilities incurred with properties drilled	-	114
Liabilities settled during the period	(160)	(372)
Liabilities associated with properties sold	(304)	-
Current period accretion	518	470
Current period revisions to oil and natural gas properties	-	6,182
Asset retirement obligation - end of period	$ 22,744	$ 15,920

(9) Unit-Based Compensation

Long-Term Incentive Plan

Concurrent with the Legacy Formation on March 15, 2006, a Long-Term Incentive Plan for Legacy was created and Legacy adopted SFAS No. 123(R)-Share-Based Payment. Legacy adopted the Legacy Reserves LP Long-Term Incentive Plan (“LTIP”) for its employees, consultants and directors, its affiliates and its general partner. The awards under the LTIP may include unit grants, restricted units, phantom units, unit options and unit appreciation rights. The LTIP permits the grant of awards covering an aggregate of 2,000,000 units. As of June 30, 2008, grants of awards net of forfeitures covering 610,466 units had been made, comprised of 493,600 unit options and unit appreciation rights awards, 65,116 restricted unit awards and 51,750 phantom unit awards. 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.

Unit Options and Unit Appreciation Rights

During the year ended December 31, 2007, Legacy issued 113,000 unit option awards to employees which vest ratably over a three-year period. All options granted in 2007 expire five years from the grant date and are exercisable when they vest. During the six-month period ended June 30, 2008, Legacy issued 84,000 unit appreciation rights

(“UARs”) to employees which vest ratably over a three-year period. All UARs granted in 2008 expire five years from the grant date and are exercisable when they vest.

For the six-month periods ended June 30, 2008 and 2007, Legacy recorded $801,369 and $1,094,656, respectively, of compensation expense due to the change in liability from December 31, 2007 and 2006 based on its use of the Black-Scholes model to estimate the June 30, 2008 and 2007 fair value of these unit options and UARs. As of June 30, 2008, there was a total of $1.4 million of unrecognized compensation costs related to the un-exercised and non-vested portion of these unit options and UARs. At June 30, 2008, this cost was expected to be recognized over a weighted-average period of approximately 1.9 years. Compensation expense is based upon the fair value as of June 30, 2008 and is recognized as a percentage of the service period satisfied. Since Legacy has limited trading history, it has used an estimated volatility factor of approximately 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 June 30, 2008 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), Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.08 per unit.

A summary of option and UAR activity for the six-months ended June 30, 2008 is as follows:

	Units		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term
Outstanding at January 1, 2008	399,422	$	19.73	
Granted	84,000	$	21.19	
Exercised	(5,330)	$	17.00	
Forfeited	(12,860)	$	19.08	
Outstanding at June 30, 2008	465,232	$	20.05	3.6 years
Options and UARs exercisable at June 30, 2008	147,798	$	18.27	2.9 years

The following table summarizes the status of Legacy's non-vested unit options and UARs since January 1, 2008:

	Non-Vested Options and UARs		
	Number of Units		Weighted-Average Fair Value
Non-vested at January 1, 2008	336,622	$	4.09
Granted	84,000		5.55
Vested - Unexercised	(84,998)		6.74
Vested - Exercised	(5,330)		6.44
Forfeited	(12,860)		3.31
Non-vested at June 30, 2008	317,434	$	5.58

Legacy has used a weighted-average risk-free interest rate of 3.3% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at June 30, 2008 whose term is consistent with the expected life of the unit options and UARs. Expected life represents the period of time that options and UARs are expected to be outstanding and is based on Legacy's best estimate. The following table represents the weighted-average assumptions used for the Black-Scholes option-pricing model.

		Six Months Ended June 30, 2008
Expected life (years)		5
Annual interest rate		3.3%
Annual distribution rate per unit	$	2.08
Volatility		42%

Restricted and Phantom Units

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

On June 27, 2007, Legacy granted 3,000 phantom units to an employee which vest ratably over a five-year period, beginning at the date of grant. On July 16, 2007, Legacy granted 5,000 phantom units to an employee which vest ratably over a five-year period, beginning at the date of grant. On December 3, 2007, Legacy granted 10,000 phantom units to an employee which vest ratably over a three-year period, beginning at the date of grant. On February 4, 2008, Legacy granted 2,750 phantom units to four employees which vest ratably over a three-year period, beginning at the date of grant. On May 1, 2008, Legacy granted 3,000 phantom units to an employee which vest ratably over a three-year period, beginning at the date of grant. In conjunction with these grants, the employees are entitled to distribution equivalent rights ("DERs") for unvested units held at the date of dividend payment. Compensation expense related to the phantom units and associated DERs was $176,638 and $275 for the six month periods ended June 30, 2008 and 2007, respectively.

On August 20, 2007, the board of directors of Legacy's general partner, upon recommendation from the Compensation Committee, approved phantom unit awards of up to 175,000 units to five key executives of Legacy based on achievement of targeted annualized per unit distribution levels over a base amount of $1.64 per unit. These awards are to be determined annually based solely on the annualized level of per unit distributions for the fourth quarter of each calendar year and subsequently vest over a three-year period. There is a range of 0% to 100% of the distribution levels at which the performance condition may be met. For each quarter, management recommends to the board an appropriate level of per unit distribution based on available cash of Legacy. The level of distribution is set by the board subsequent to management's recommendation. Probable issuances for the purposes of calculating compensation expense associated therewith are determined based on management's determination of probable future distribution levels. Expense associated with probable vesting is recognized over the period from the date probable vesting is determined to the end of the three-year vesting period. On February 4, 2008 the Compensation Committee approved the award of 28,000 phantom units to our five executive officers. In conjunction with these grants, the executive officers are entitled to DERs for unvested units held at the date of dividend payment. Compensation expense related to the phantom units and associated DERs was $315,865 for the six months ended June 30, 2008.

On March 15, 2006, Legacy issued an aggregate of 52,616 restricted units to two employees. The restricted units awarded vest ratably over a three-year period, beginning on the date of grant. On May 5, 2006, Legacy issued 12,500 restricted units to an employee. The restricted units awarded vest ratably over a five-year period, beginning on March 31, 2007. Compensation expense related to restricted units was $170,328 for both the six months ended June, 30, 2008 and 2007. As of June 30, 2008, there was a total of $325,946 of unrecognized compensation expense related to the non-vested portion of these restricted units. At June 30, 2008, this cost was expected to be recognized over a weighted-average period of 1.4 years. Pursuant to the provisions of SFAS 123(R), Legacy's issued units, as reflected in the accompanying consolidated balance sheet at June 30, 2008, do not include 25,040 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. On November 26, 2007, Legacy granted and issued 1,750 units to each of its four non-employee directors as part of their annual compensation for serving on Legacy's board. The value of each unit was $21.32 at the time of grant. On March 5, 2008, Legacy issued 583 units, granted on January 23, 2008, to its newly elected non-employee director as part of his pro-rata annual compensation for serving on Legacy's board. The value of each unit was $21.20 at the time of grant.

(10) Subsequent Events

On July 22, 2008, Legacy's Board of Directors approved a distribution of $0.52 per unit payable on August 14, 2008 to unitholders of record on August 1, 2008.

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

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

The forward-looking statements contained in this document are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this document are not guarantees of future performance, and 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, 2007 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 formation of Legacy on March 15, 2006, we acquired oil and natural gas properties and business operations from our Founding

Investors and three charitable foundations.

Because of our rapid growth through acquisitions and development of properties, historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results. The operating results 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, the operating results of the Raven OBO properties have been included from August 3, 2007, the operating results from the TOC and Summit Acquisitions have been included from October 1, 2007 and the operating results from the COP III Acquisition have been included from April 30, 2008.

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

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

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

Higher oil and natural gas prices have led to higher demand for drilling rigs, oilfield tubular goods, 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, re-stimulating existing wells and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on adding reserves through acquisitions and exploitation projects. Our ability to add reserves through acquisitions and exploitation projects is dependent upon many factors including our ability to raise capital, obtain regulatory approvals and contract drilling rigs and personnel.

Our revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. As set forth under "Cash Flow from Operations" below, we have hedged a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our capital investment programs and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact, if any, on any re-determination of 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. As of June 30, 2008, the fair market value of Legacy's commodity derivative positions was a net liability of $317.6 million based on NYMEX near month prices of $140.00 per Bbl and $13.35 per MMBtu for oil and natural gas, respectively. As of December 31, 2007, the fair market value of Legacy's commodity derivative positions was a net liability of $82.3 million based on NYMEX near month prices of $95.98 per Bbl and $7.48 per MMBtu for oil and natural gas, respectively. As of July 31, 2008, the NYMEX near month prices for oil and natural gas were $124.08 per Bbl and $9.12 per MMBtu, respectively. As a direct result , the net liability related to the fair market value of Legacy's commodity derivative positions decreased by $102.8 million.

Production and Operating Costs Reporting

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

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

Operating Data

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 48,439	$ 16,654	$ 84,488	$ 28,954
Natural gas liquid sales	4,781	1,072	8,283	1,177
Natural gas sales	13,389	5,010	22,625	8,536
Total revenue	$ 66,609	$ 22,736	$ 115,396	$ 38,667
Expenses:				
Oil and natural gas production	$ 13,515	$ 6,088	$ 23,042	$ 10,828
Production and other taxes	$ 4,089	$ 1,481	$ 6,558	$ 2,475
General and administrative	$ 3,696	$ 2,769	$ 6,714	$ 4,595
Depletion, depreciation, amortization and accretion	$ 10,523	$ 6,811	$ 20,140	$ 12,106
Realized swap settlements				
Realized gain (loss) on oil swaps	$ (12,595)	$ 843	$ (19,173)	$ 2,045
Realized loss on natural gas liquid swaps	$ (1,012)	$ (41)	$ (1,733)	$ (42)
Realized gain (loss)on natural gas swaps	$ (1,535)	$ 560	$ (1,002)	$ 1,824
Realized gain (loss) on interest rate swaps	$ (162)	$ -	$ 122	$ -
Production:				
Oil - barrels	396	273	775	501
Natural gas liquids - gallons	2,821	856	5,543	959
Natural gas - Mcf	1,238	718	2,296	1,306
Total (MBoe)	670	413	1,290	742
Average daily production (Boe/d)	7,363	4,538	7,088	4,099
Average sales price per unit:				
Oil price per barrel	$ 122.32	$ 61.00	$ 109.02	$ 57.79
Natural gas liquid price per gallon	$ 1.69	$ 1.25	$ 1.49	$ 1.23
Natural gas price per Mcf	$ 10.82	$ 6.98	$ 9.85	$ 6.54
Combined (per Boe)	$ 99.42	$ 55.05	$ 89.45	$ 52.11
Average sales price per unit (including realized swap settlements):				
Oil price per barrel	$ 90.52	$ 64.09	$ 84.28	$ 61.87
Natural gas liquid price per gallon	$ 1.34	$ 1.20	$ 1.18	$ 1.18
Natural gas price per Mcf	$ 9.58	$ 7.76	$ 9.42	$ 7.93
Combined (per Boe)	$ 76.82	$ 58.35	$ 72.47	$ 57.27
NYMEX oil index prices per barrel:				
Beginning of Period	$ 101.58	$ 65.87	$ 95.98	$ 61.05
End of Period	$ 140.00	$ 70.68	$ 140.00	$ 70.68

NYMEX gas index prices per Mcf:								
Beginning of Period	$	10.10	$	7.73	$	7.48	$	6.30
End of Period	$	13.35	$	6.77	$	13.35	$	6.77
Average unit costs per Boe:								
Production costs, excluding production and other taxes	$	20.17	$	14.74	$	17.86	$	14.59
Production and other taxes	$	6.10	$	3.59	$	5.08	$	3.34
General and administrative	$	5.52	$	6.70	$	5.20	$	6.19
Depletion, depreciation, amortization and accretion	$	15.71	$	16.49	$	15.61	$	16.32

Results of Operations

Three-Month Period Ended June 30, 2008 Compared to Three-Month Period Ended June 30, 2007

Legacy's revenues from the sale of oil were $48.4 million and $16.7 million for the three-month periods ended June 30, 2008 and 2007, respectively. Legacy's revenues from the sale of NGLs were $4.8 million and $1.1 for the three-month periods ended June 30, 2008 and 2007, respectively. Legacy's revenues from the sale of natural gas were $13.4 million and $5.0 million for the three-month periods ended June 30, 2008 and 2007, respectively. The $31.7 million increase in oil revenues reflects an increase in oil production of 123 MBbls (45%) due primarily to Legacy's purchase of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions and the increase in average realized price of $61.32 per Bbl. The $3.7 million increase in proceeds from NGL sales reflects an increase in NGL production of approximately 1,965 MMGal (230%) due primarily to Legacy's purchase of oil and natural gas properties in the Binger, Ameristate, Raven Shenandoah, Raven OBO, TOC and COP III Acquisitions. The $8.4 million increase in natural gas revenues reflects an increase in natural gas production of approximately 520 MMcf (72%) due primarily to Legacy's purchase of oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions, and the increase in average realized price per Mcf of $3.84 per Mcf.

For the three-month period ended June 30, 2008, Legacy recorded $216.4 million of net losses on oil, NGL and natural gas swaps comprised of realized losses of $15.1 million from net cash settlements of oil, NGL and natural gas swap contracts and net unrealized losses of $201.3 million. Legacy had large unrealized net losses from oil swaps because the fixed prices of its oil swap contracts were below the NYMEX index prices at June 30, 2008. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close increased from $101.58 per Bbl at March 31, 2008 to $140.00 per Bbl at June 30, 2008, a price which is greater than the average contract prices of Legacy's outstanding oil swap contracts. Due to the substantial 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 NGL swaps because the fixed prices of its NGL swap contracts were below the NYMEX index prices at June 30, 2008. Legacy had unrealized net losses from natural gas swaps because the fixed prices of its natural gas swap contracts were below the NYMEX index prices at June 30, 2008. In addition, the NYMEX price for natural gas for the near-month close increased from $10.10 per MMBtu at March 31, 2008 to $13.35 per MMBtu at June 30, 2008, a price which is greater than the average contract prices of Legacy's outstanding natural gas swap contracts. For the three-month period ended June 30, 2007, Legacy recorded $6.5 million of net losses on oil and natural gas swaps comprised of realized gains of $1.4 million from net cash settlements of oil, NGL and natural gas swap contracts and a net unrealized loss of $8.1 million on oil swap contracts, due to the increase in oil prices during the quarter which increased the differential between the NYMEX oil index price and our fixed price oil swaps, a net unrealized loss of $0.3 million on NGL swap contracts and a net unrealized gain of $0.5 million on natural gas swap contracts, due to the decrease in natural gas prices which decreased 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 $13.5 million ($20.17 per Boe) for the three-month period ended June 30, 2008, from $6.1 million ($14.74 per Boe) for the three-month period ended June 30, 2007. Production expenses increased primarily because of (i) $4.8 million of production expenses related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions, (ii) $0.9 million related to individually non-material acquisitions and (iii) $0.7 million related to increases in ad valorem expenses from higher valuations related to increased oil and natural gas prices, increased well counts and periods of ownership. In addition, the increase in production costs per Boe is consistent with industry-wide cost increases, particularly those directly related to higher commodity prices, such as the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil.

Legacy's production and other taxes were $4.1 million and $1.5 million for the three-month periods ended June 30, 2008 and 2007, respectively. Production and other taxes increased primarily because of approximately $1.3 million of taxes related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions. The increase in production and other taxes is primarily due to the increase in realized prices. As production and other taxes are a function of price and volume, the increase is consistent with the increase in realized prices.

Legacy's general and administrative expenses were $3.7 million and $2.8 million for the three-month periods ended June 30, 2008 and 2007, respectively. General and administrative expenses increased approximately $0.9 million between the three-month periods ended June 30, 2008 and 2007 primarily due to (i) a $0.7 million increase in salaries related to an increased headcount due to growth in our asset base and (ii) a $0.2 million increase in compensation expense related to our LTIP.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $10.5 million and $6.8 million for the three-month periods ended June 30, 2008 and 2007, respectively, reflecting primarily $3.7 million of DD&A related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions. In addition, the decrease in DD&A expense per Boe, from $16.49 to $15.71 for the three-month periods ended June 30, 2007 and 2008, 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 $4,030 and $189,730 for the three-month periods ended June 30, 2008 and 2007, respectively. In the period ended June 30, 2008, Legacy recognized impairment expense in two producing fields, due primarily to additional costs incurred during the period ended June 30, 2008 on a field from which the future estimated production revenues did not exceed these costs. The impairment expense for the period ended June 30, 2007, involved eight separate fields due primarily to costs incurred in the period during which the estimated production revenues did not exceed the costs.

Legacy recorded interest income of $15,395 for the three-month period ended June 30, 2008, and $46,850 for the three-month period ended June 30, 2007. The decrease of $31,455 is a result of lower average cash balances and lower interest rates for the period ended June 30, 2008.

Due to the $3.6 million mark-to-market gain related to Legacy’s interest rate swaps recorded in earnings for the three-month period ended June 30, 2008, interest expense for the three-month period ended June 30, 2008 reflects income of $1.2 million comprised of the $3.6 million gain and actual interest charges of $2.4 million. Legacy recorded interest expense of $0.9 million for the three-month period ended June 30, 2007. The higher actual interest charges in the period ended June 30, 2008, over the period ended June 30, 2007, reflect higher average borrowings in the period ended June 30, 2008. Legacy repaid the entire $115.8 million outstanding under its revolving credit facility at the close of its initial public offering on January 18, 2007

Legacy recognized $45,398 and $10,910 in income from its equity interest in the Binger Operations, LLC (“BOL”) for the three-month period ended June 30, 2008 and 2007, respectively. This income is primarily derived from BOL’s less than 1% interest in the Binger Unit. The increase of $34,488 is a result of Legacy’s ownership in BOL for the entire three-month period ended June 30, 2008, whereas Legacy owned the interest for only two months during the three-month period ended June 30, 2007. The additional increase relates to higher average commodity prices in the period ended June 30, 2008, compared to the three-month period ended June 30, 2007.

During the three-month period ended June 30, 2008, Legacy recorded a gain of $4.9 million related to the disposal of our 12.9% non-operated working interest in the Reeves Unit in a non-monetary transaction with Devon Energy in exchange for 60% interest in two operated properties. In addition, Legacy paid $630,000 of cash boot in the transaction. Due to the significant differences in the risk and timing of the cash flows from the exchanged property sets, Legacy has treated this exchange as one having commercial substance. As such, we have calculated the gain on disposal of this discontinued operation based on the fair value of our interest in the Reeves Unit. Due to immateriality, we have not reflected the operating results of the Reeves Unit separately as a discontinued operation for any of the periods presented.

Six-Month Period Ended June 30, 2008 Compared to Six-Month Period Ended June 30, 2007

Legacy’s revenues from the sale of oil were $84.5 million and $29.0 million for the six-month periods ended June 30, 2008 and 2007, respectively. Legacy’s revenues from the sale of NGLs were $8.3 million and $1.2 million for the six-month periods ended June 30, 2008 and 2007, respectively. Legacy’s revenues from the sale of natural gas were $22.6 million and $8.5 million for the six-month periods ended June 30, 2008 and 2007, respectively. The $55.5 million increase in oil revenues reflects an increase in oil production of 274 MBbls (55%) due primarily to Legacy’s purchase of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions and the increase in average realized price of $51.23 per Bbl. The $7.1 million increase in NGLs is due primarily to Legacy’s purchase of oil and natural gas properties in the Binger, Ameristate, Raven Shenandoah, Raven OBO, TOC and COP III Acquisitions. The $14.1 million increase in natural gas revenues reflects an increase in natural gas production of approximately 990 MMcf (76%) due primarily to Legacy’s purchase of oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions, and the increase in average realized price of $3.31 per Mcf.

For the six-month period ended June 30, 2008, Legacy recorded $257.3 million of net losses on oil, NGL and natural gas swaps comprised of realized losses of $21.9 million from net cash settlements of oil, NGL and natural gas swap contracts and net unrealized losses of $235.4 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 June 30, 2008. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close increased from $95.98 per Bbl at December 31, 2007 to $140.00 per Bbl at June 30, 2008, 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 six-month period ended June 30, 2008, the differential between Legacy’s fixed price oil swaps and NYMEX increased, resulting in losses for the six-months ended June 30, 2008. Legacy had unrealized net losses from NGL swaps because the fixed prices of its NGL swap contracts were below the NYMEX index prices at June 30, 2008. Legacy had unrealized net losses from natural gas swaps because the fixed prices of its natural gas swap contracts were below the NYMEX index prices at June 30, 2008. In addition, the NYMEX price for natural gas for the near-month close increased from $7.48 per MMBtu at December 31, 2007 to $13.35 per MMBtu at June 30, 2008, a price which is greater than the average contract prices of Legacy’s outstanding natural gas swap contracts. For the six-month period ended June 30, 2007, Legacy recorded $13.7 million of net losses on oil, NGL and natural gas swaps. This net loss is comprised of realized gains of $3.8 million from net cash settlements of oil and natural gas swap contracts and a net unrealized loss of $13.2 million on oil swap contracts. The unrealized loss on oil swap contracts is due to the increase in oil prices during the quarter ended June 30, 2007, which increased the differential between the NYMEX oil index price and our fixed price oil swaps. The remaining balance is due to a net unrealized loss of $0.3 million on NGL swap contracts and a net unrealized loss of $4.0 million on natural gas swap contracts. The unrealized loss on natural gas swap contracts is due to the increase 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 $23.0 million ($17.86 per Boe) for the six-month period ended June 30, 2008, from $10.8 million ($14.59 per Boe) for the six-month period ended June 30, 2007. Production expenses increased primarily because of (i) $8.3 million of production expenses related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions, (ii) $0.9 million related to individually non-material acquisitions and (iii) $1.0 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 cost increases, particularly those directly related to higher commodity prices, such as the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil.

Legacy's production and other taxes were $6.6 million and $2.5 million for the six-month periods ended June 30, 2008 and 2007, respectively. Production and other taxes increased primarily because of approximately $2.2 million of taxes related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions. The remaining increase in production and other taxes is primarily due to the increase in realized prices. As production and other taxes are a function of price and volume, the increase is consistent with the increase in realized prices.

Legacy's general and administrative expenses were $6.7 million and $4.6 million for the six-month periods ended June 30, 2008 and 2007, respectively. General and administrative expenses increased approximately $2.1 million between periods primarily due to (i) $1.3 million increase in executive salaries, (ii) $0.4 million increase in accounting and audit fees, (iii) $0.2 million increase in compensation expense related to our LTIP and (iv) increased employee costs related to business expansion.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $20.1 million and $12.1 million for the six-month periods ended June 30, 2008 and 2007, respectively, reflecting primarily $7.1 million of DD&A related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit and COP III Acquisitions. In addition, the decrease in DD&A expense per Boe, from $16.32 to $15.61 for the six-month periods ended June 30, 2007 and 2008, 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 $108,185 and $279,700 for the six-month periods ended June 30, 2008 and 2007, respectively. In the period ended June 30, 2008, Legacy recognized impairment expense in three producing fields, due primarily to additional costs incurred during the period ended June 30, 2008 on fields from which the future estimated production revenues did not exceed these costs. The impairment expense for the period ended June 30, 2007, involved eight separate fields due primarily to costs incurred in the period during which the estimated production revenues did not exceed the costs.

Legacy recorded interest income of $70,652 for the six-month period ended June 30, 2008 and $151,158 for the six-month period ended June 30, 2007. The decrease of $80,506 is a result of lower average cash balances for the period ended June 30, 2008.

Interest expense was $3.0 million and $1.5 million for the six-month periods ended June 30, 2008 and 2007, respectively, reflecting higher average borrowings in the period ended June 30, 2008. Legacy repaid the entire $115.8 million outstanding under its revolving credit facility at the close of its initial public offering on January 18, 2007. In addition, Legacy recorded a $1.4 million reduction in non-cash interest expense related to the mark-to-market of its interest rate swaps for the six-month period ended June 30, 2008.

Legacy recognized $87,415 and $10,910 in income from its equity interest in BOL for the six-month periods ended June 30, 2008 and 2007, respectively. This income is primarily derived from BOL's less than 1% interest in the Binger Unit.

During the six-month period ended June 30, 2008, Legacy recorded a gain of $4.9 million related to the disposal of our 12.9% non-operated working interest in the Reeves Unit in a non-monetary transaction with Devon Energy in exchange for 60% interest in two operated properties. In addition, Legacy paid $630,000 of cash boot in the transaction. Due to the significant differences in the risk and timing of the cash flows from the exchanged property sets, Legacy has treated this exchange as one having commercial substance. As such, we have calculated the gain on disposal of this discontinued operation based on the fair value of our interest in the Reeves Unit. Due to immateriality, we have not reflected the operating results of the Reeves Unit separately as a discontinued operation for any of the periods presented.

Capital Resources and Liquidity

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

As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and developing additional 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, 2008, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our credit facility will provide us sufficient working capital to meet our planned capital expenditures of $28.6 million and planned annual cash distributions of $60.9 million for 2008, which includes the $13.4 million and $15.2 million of distributions paid in the first and second quarters of 2008, respectively, and $16.15 million of planned distributions during each of the third and fourth quarters of 2008. Please read "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Legacy's net cash provided by operating activities was $67.4 million and $15.0 million for the six-month periods ended June 30, 2008 and 2007, respectively, with the 2008 period being favorably impacted by higher sales volumes and higher commodity prices, 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, NGL and natural gas derivatives to reduce the impact of oil, NGL and natural gas price volatility on our operations. Currently, we use swaps and collars to offset price volatility on NYMEX oil, NGL and natural gas prices, which do not include the additional net discount that we typically experience in the Permian Basin. At June 30, 2008, we had in place oil, NGL and natural gas swaps covering significant portions of our estimated 2008 through 2012 oil, NGL and natural gas production. We have swap contracts covering approximately 71% of our remaining expected oil, natural gas liquid and natural gas production for 2008. We also have swap contracts covering approximately 59% of our currently expected oil and natural gas production for 2009 through 2012 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 and collars as our mechanism for offsetting the cash flow effects of changes in commodity prices whereby we pay the counterparty floating prices and receive fixed prices from the counterparty, which serves to reduce the effects on cash flow of the floating prices we are paid by purchasers of our oil and natural gas. These transactions are settled based upon the 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	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July - December 2008	646,579	$ 74.19	$62.25 - $101.47
2009	1,343,613	$ 79.99	$61.05 - $140.00
2010	1,261,045	$ 79.47	$60.15 - $140.00
2011	1,025,840	$ 85.42	$67.33 - $140.00
2012	750,000	$ 76.85	$67.72 - $101.47

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
July - December 2008	1,589,437	$ 8.05	$6.85 - $9.10
2009	2,924,042	$ 8.06	$6.85 - $10.18
2010	2,610,359	$ 7.85	$6.85 - $9.73
2011	1,908,616	$ 8.00	$6.85 - $8.70
2012	1,371,036	$ 8.01	$6.85 - $8.70

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

Calendar Year	Volumes (MMBtu)	Basis Range per Mcf
July - December 2008	711,000	($0.84)
2009	1,320,000	($0.68)
2010	1,200,000	($0.57)

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

Calendar Year	Volumes (Gal)	Average Price per Gal	Price Range per Gal
July - December 2008	3,145,380	$ 1.28	$0.66 - $1.62
2009	2,265,480	$ 1.15	$1.15

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

Calendar Year	Volumes (Bbls)	Average Floor	Average Ceiling
2009	75,400	$ 120.00	$ 156.30
2010	71,800	$ 120.00	$ 156.30
2011	68,300	$ 120.00	$ 156.30
2012	65,100	$ 120.00	$ 156.30

Investing Activities — Acquisitions and Capital Expenditures

Legacy’s cash capital expenditures were $113.6 million for the six-month period ended June 30, 2008. The total includes $106.3 million for acquisition of oil and natural gas properties in the COP III Acquisition and several small acquisitions and $7.3 million of development projects.

Legacy's cash capital expenditures were $69.8 million for the six-month period ended June 30, 2007. The total includes $61.8 million for the acquisition of oil and natural gas properties in four acquisitions and $8.0 million of development projects.

We currently anticipate that our drilling budget, which predominantly consists of drilling, re-completion and re-fracture stimulation projects will be $28.6 million for the year ending December 31, 2008. Our remaining borrowing capacity under our revolving credit facility is $102.7 million as of August 6, 2008. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. 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, casing and tubing and labor crews. Based upon current oil and natural gas price expectations for the year ending December 31, 2008, we anticipate that we will have sufficient sources of working capital, including our cash flow from operations and available borrowing capacity under our credit facility, to meet our cash obligations including our planned capital expenditures of $28.6 million and planned annual cash distributions of $60.9 million for the year ending December 31, 2008. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Our Revolving Credit Facility

At the closing of our private equity offering on March 15, 2006, we entered into a four-year, $300 million revolving credit facility with BNP Paribas as administrative agent. 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, currently at $320 million, which was initially set at $130 million and was increased on April 24, 2008 to $272 million. Pursuant to the Fourth Amendment to the credit agreement, the borrowing base was initially increased to $272 million and increased further to $320 million coincident with the closing of the COP III Acquisition, which closed on April 30, 2008, and the satisfaction of certain customary conditions under the credit facility. 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 request the re-determination of the borrowing base upon the proposed acquisition of certain oil and gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders and any decrease in the borrowing base must be approved by the lenders holding 66 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 0.25%, or
- with respect to any Eurodollar loans for any interest period, the London interbank rate, or LIBOR, plus an applicable margin ranging from and including 1.25% and 1.875% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

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

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

- incur indebtedness;
- enter into certain leases;
- grant certain liens;

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

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

- consolidated net income 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 $1.0 million in any year.

At June 30, 2008, Legacy was in compliance with all financial and other covenants of the credit facility.

Off-Balance Sheet Arrangements

None.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon the 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 here and in our annual report on Form 10-K for the period ended December 31, 2007 for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

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

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

Effect if Different Assumptions Used: Units-of-production method to deplete our oil and natural gas properties — A 10% increase or decrease in reserves would have decreased or increased, respectively, our depletion expense for the three-month period ended June 30, 2008 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, NGL 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, NGL and natural gas for a fixed price with qualified and creditworthy counterparties (currently BNP Paribas, Bank of America, KeyBank and Wachovia). Our existing oil, NGL 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, NGL and natural gas prices and interest rate changes. Therefore, the mark-to-market of these instruments is recorded in current earnings. We use market value statements from each of our counterparties as the basis for these end-of-period mark-to-market adjustments. We currently have engaged a third-party provider to calculate an independent mark-to-market statement to evaluate the reasonableness of our counterparties' statements. 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 2012. As oil, NGL and natural gas prices rise and fall, our future cash obligations related to these derivatives will rise and fall.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements. Statement No. 157 defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in GAAP and expands disclosure related to the use of fair value measures in financial statements. We adopted the statement effective January 1, 2008 and the adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows. See Note 6 for other disclosures required by Statement No. 157.

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

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 160, Non-controlling Interest in Consolidated Financial Statements – an amendment of ARB No. 51 ("SFAS 160"). SFAS 160 requires that accounting and reporting for minority interests will be re-characterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008, which will be the Partnership's fiscal year 2009. Based upon the June 30, 2008 balance sheet, the statement would have no impact.

Item 3. Quantitative and Qualitative Disclosure About Market Risk.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

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

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

As of June 30, 2008, the fair market value of Legacy's commodity derivative positions was a net liability of $317.6 million based on NYMEX near month prices of $140.00 per Bbl and $13.35 per MMBtu for oil and natural gas, respectively. As of December 31, 2007, the fair market value of Legacy's commodity derivative positions was a net liability of $82.3 million based on NYMEX near month prices of $95.98 per Bbl and $7.48 per MMBtu for oil and natural gas, respectively. As of July 31, 2008, the NYMEX near month prices for oil and natural gas were $124.08 per Bbl and $9.12 per MMBtu, respectively. As a direct result , the net liability related to the fair market value of Legacy's commodity derivative positions decreased by $102.8 million. The oil, NGL and natural gas swaps for 2008 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."

Interest Rate Risks

At June 30, 2008, Legacy had debt outstanding of $206.0 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for the six-month period ended June 30, 2008 was 5.23%. A 1% increase in LIBOR on Legacy's outstanding debt as of June 30, 2008 would result in an estimated $0.9 million increase in annual interest expense as Legacy has entered into interest rate swaps to mitigate the volatility of interest rates through November of 2011 on $114 million of floating rate debt to a weighted average fixed rate of 3.69%.

Item 4T. 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 June 30, 2008. 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 June 30, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

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

Item 1A. RISK FACTORS

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, 2007, 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, 2007 are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

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

Our annual meeting of unitholders was held Monday, May 19, 2008. The item submitted to unitholders for vote was the election of seven nominees to serve on the board of directors of our general partner during 2008 and until our next annual meeting. Notice of the meeting and proxy information was distributed to unitholders prior to the meeting in accordance with law. There were no solicitations in opposition to the nominees. Out of a total of 29,715,965 units outstanding and entitled to vote, 24,870,341 units (83.69%) were present at the meeting in person or by proxy.

Election of Directors

There were seven nominees for election to serve as directors of our general partner. Each of the nominees for election to the board of directors was currently a director of Legacy Reserves GP, LLC. The vote tabulation with respect to each nominee to the Board was as follows:

Nominee	For	Withheld
Cary D. Brown	24,754,700	115,641
Kyle A. McGraw	24,756,775	113,566
Dale A. Brown	24,703,134	167,207
G. Larry Lawrence	24,755,427	114,914
William D. (Bill) Sullivan	24,756,949	113,392
William R. Granberry	24,766,492	103,849
Kyle D. Vann	24,756,047	114,294

Item 5. Other Information.

None.

Item 6. Exhibits.

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.1)
3.2	Amended and Restated Limited Partnership Agreement of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 33-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	Amendment No.1, dated December 27, 2007, to the Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's Current Report on Form 8-K (File No. 001-33249) filed January 2, 2008, Exhibit 3.1)
3.4	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.5	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
4.1	Registration Rights Agreement dated June 29, 2006 between Henry Holding LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the "Henry Registration Rights Agreement") (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.2)
4.2	Registration Rights Agreement dated March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (the "Founders Registration Rights Agreement") (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.3)
4.3	Registration Rights Agreement dated April 16, 2007 by and among Nielson & Associates, Inc., Legacy Reserves GP, LLC and Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP's Quarterly Report on Form 10-Q (File No. 001-33249) filed May 14, 2007, Exhibit 4.4)
10.1	Fourth Amendment to Credit Agreement dated April 24, 2008 (Incorporated by reference to Legacy Reserves LP's Current Report on Form 8-K (File No. 001-33249) filed April 25, 2008, Exhibit 10.1)
10.2	Purchase, Sale and Contribution Agreement dated March 13, 2008, by and among Crown Oil Partners III, LP, BC Operating, Inc. and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP's Current Report on Form 8-K (File No. 001-33249) filed May 5, 2008, Exhibit 10.1)
31.1*	Rule 13a-14(a) Certifications (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	Rule 13a-14(a) Certifications (under Section 302 of the Sarbanes-Oxley Act of 2002)
32.1*	Section 1350 Certifications (under Section 906 of the Sarbanes-Oxley Act of 2002)

* Filed herewith