LEGACY RESERVES LP
Form 10-Q
August 01, 2014

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

FORM 10-Q

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

SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2014

or

£ 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 1800 Midland, Texas (Address of principal executive offices)	79701 (Zip code)

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

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

x Yes o No

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

x Yes £ No

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

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

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

57,669,495 units representing limited partner interests in the registrant were outstanding as of July 31, 2014.

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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.

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

Liquids. Oil and NGLs.

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

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

Mcf. One thousand cubic feet.

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

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

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

NGL 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 and condensate.

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

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

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

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

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

Proved undeveloped reserves or PUDs. Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

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 projects. The reserve replacement cost may not be indicative of the economic value added of the reserves due to differing lease operating expenses per barrel and differing timing of production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provisions for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to 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, 2014	December 31, 2013
	(In thousands)	
Current assets:		
Cash	$10,139	$2,584
Accounts receivable, net:		
Oil and natural gas	66,322	47,429
Joint interest owners	25,454	16,532
Other	721	626
Fair value of derivatives (Notes 6 and 7)	823	3,801
Prepaid expenses and other current assets	6,076	3,727
Total current assets	109,535	74,699
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	2,819,660	2,265,788
Unproved properties	81,511	58,392
Accumulated depletion, depreciation, amortization and impairment	(857,983)	(788,751)
	2,043,188	1,535,429
Other property and equipment, net of accumulated depreciation and amortization of $6,739 and $6,053, respectively	3,573	3,688
Deposits on pending acquisitions	5,800	—
Operating rights, net of amortization of $4,266 and $4,024, respectively	2,750	2,992
Fair value of derivatives (Notes 6 and 7)	3,158	21,292
Other assets, net of amortization of $11,214 and $10,097, respectively	25,181	17,641
Investments in equity method investees	3,146	4,092
Total assets	$2,196,331	$1,659,833

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)
LIABILITIES AND PARTNERS' EQUITY

	June 30, 2014	December 31, 2013
	(In thousands)	
Current liabilities:		
Accounts payable	$13,093	$6,016
Accrued oil and natural gas liabilities (Note 1)	83,596	63,161
Fair value of derivatives (Notes 6 and 7)	24,008	10,060
Asset retirement obligation (Note 8)	2,610	2,610
Other (Note 10)	14,203	12,043
Total current liabilities	137,510	93,890
Long-term debt (Note 2)	1,153,687	878,693
Asset retirement obligation (Note 8)	219,188	173,176
Fair value of derivatives (Notes 6 and 7)	3,331	2,119
Other long-term liabilities	1,635	1,559
Total liabilities	1,515,351	1,149,437
Commitments and contingencies (Note 5)		
Partners' equity (Note 9):		
Series A Preferred equity - 2,300,000 units issued and outstanding at June 30, 2014	55,192	—
Series B Preferred equity - 7,000,000 units issued and outstanding at June 30, 2014	169,102	—
Incentive distribution equity - 100,000 units issued and outstanding at June 30, 2014	30,814	—
Limited partners' equity - 57,405,398 and 57,280,049 units issued and outstanding at June 30, 2014 and December 31, 2013	425,800	510,322
General partner's equity (approximately 0.03%)	72	74
Total partners' equity	680,980	510,396
Total liabilities and partners' equity	$2,196,331	$1,659,833

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$108,731	$97,852	$210,786	$188,209
Natural gas liquids (NGL) sales	5,103	3,161	9,069	6,503
Natural gas sales	23,280	17,373	43,163	32,553
Total revenues	137,114	118,386	263,018	227,265
Expenses:				
Oil and natural gas production	45,809	37,184	88,343	72,535
Production and other taxes	8,595	6,771	16,550	13,698
General and administrative	14,809	7,064	22,456	13,346
Depletion, depreciation, amortization and accretion	38,537	39,113	72,234	80,765
Impairment of long-lived assets	2,387	20,774	3,798	22,517
Gain on disposal of assets	(3,853)	(46)	(1,552)	(265)
Total expenses	106,284	110,860	201,829	202,596
Operating income	30,830	7,526	61,189	24,669
Other income (expense):				
Interest income	216	334	439	342
Interest expense (Notes 2, 6 and 7)	(16,225)	(11,206)	(30,164)	(21,898)
Equity in income of equity method investees	191	140	183	185
Net gains (losses) on commodity derivatives (Notes 6 and 7)	(31,433)	25,330	(47,319)	12,325
Other	211	(2)	304	4
Income (loss) before income taxes	(16,210)	22,122	(15,368)	15,627
Income tax expense	(278)	(368)	(592)	(578)
Net income (loss)	$(16,488)	$21,754	$(15,960)	$15,049
Distributions to Preferred unitholders	(2,194)	—	(2,194)	—
Net income (loss) attributable to unitholders	$(18,682)	$21,754	$(18,154)	$15,049
Income (loss) per unit - basic and diluted (Note 9)	$(0.33)	$0.38	$(0.32)	$0.26
Weighted average number of units used in computing net income per unit -				
Basic	57,372	57,246	57,341	57,162
Diluted	57,372	57,349	57,341	57,195

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2014
(UNAUDITED)

	Series A Preferred Equity		Series B Preferred Equity		Incentive Distribution Equity		Unitholders' Equity			
	Units	Amount	Units	Amount	Units	Amount	Limited Partner Units	Limited Partner Amount	General Partner Amount	Total Partners' Equity
	(In thousands)									
Balance, December 31, 2013	—	$—	—	$—	—	$—	57,280	$510,322	$74	$510,396
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	18	499	—	499
Issuance of preferred units, net	2,300	55,192	7,000	169,102	—	—	—	—	—	224,294
Unit-based compensation	—	—	—	—	—	—	—	1,683	—	1,683
Vesting of restricted and phantom units	—	—	—	—	—	—	107	—	—	—
Offering costs associated with the issuance of units	—	—	—	—	—	—	—	(50)	—	(50)
Incentive Distribution Units issued in exchange for oil and natural gas properties	—	—	—	—	100	30,814	—	—	—	30,814
Distributions to preferred unitholders	—	—	—	—	—	—	—	(2,194)	—	(2,194)
Distributions to unitholders, $1.185 per unit	—	—	—	—	—	—	—	(68,502)	—	(68,502)
Net loss	—	—	—	—	—	—	—	(15,958)	(2)	(15,960)
Balance, June 30, 2014	2,300	$55,192	7,000	$169,102	100	$30,814	57,405	$425,800	$72	$680,980

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30, 2014	2013
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(15,960)	$15,049
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	72,234	80,765
Amortization of debt discount and issuance costs	2,111	1,828
Impairment of long-lived assets	3,798	22,517
(Gain) loss on derivatives	45,893	(15,394)
Equity in income of equity method investees	(183)	(185)
Distribution from equity method investee	1,129	399
Unit-based compensation	1,580	1,061
Gain on disposal of assets	(1,552)	(265)
Changes in assets and liabilities:		
Increase in accounts receivable, oil and natural gas	(18,893)	(8,068)
(Increase) decrease in accounts receivable, joint interest owners	(8,922)	9,070
(Increase) decrease in accounts receivable, other	(95)	140
Increase in other assets	(1,676)	(1,377)
Increase in accounts payable	7,078	2,339
Increase in accrued oil and natural gas liabilities	20,435	19,662
Decrease in other liabilities	(3,208)	(4,266)
Total adjustments	119,729	108,226
Net cash provided by operating activities	103,769	123,275
Cash flows from investing activities:		
Investment in oil and natural gas properties	(503,220)	(132,618)
Increase in deposits on pending acquisitions	(5,800)	—
Proceeds from sale of assets	3,281	294
Investment in other equipment	(571)	(1,459)
Net cash settlements on commodity derivatives	(9,620)	1,285
Net cash used in investing activities	(515,930)	(132,498)
Cash flows from financing activities:		
Proceeds from long-term debt	1,011,000	561,263
Payments of long-term debt	(737,000)	(485,000)
Payments of debt issuance costs	(9,331)	(872)
Proceeds from issuance of units, net	224,244	(11)
Distributions to unitholders	(69,197)	(65,663)
Redemption of investment	—	(12)
Net cash provided by financing activities	419,716	9,705
Net increase in cash and cash equivalents	7,555	482
Cash and cash equivalents, beginning of period	2,584	3,509
Cash and cash equivalents, end of period	$10,139	$3,991

Non-cash investing and financing activities:

Asset retirement obligations associated with properties sold	$(3,641)	$(1,590)
Asset retirement obligations associated with property acquisitions	48,230	$9,812
Units issued in exchange for equity method investee	$—	4,001
Note receivable received in exchange for the sale of oil and natural gas properties	$—	$11,857
Incentive distribution units issued in exchange for oil and natural gas properties	$30,814	$—

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 ("LRLP," "Legacy" or the "Partnership") and, unless the context indicates otherwise, its affiliated entities, are referred to as Legacy in these financial statements.

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, 2014 and for the three and six months ended June 30, 2014 and 2013 are unaudited. In the opinion of management, such financial statements include the adjustments and accruals, all of which are of a normal recurring nature, which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results for a full year.

Certain information and footnote disclosures normally included in 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 (“SEC”). These condensed consolidated financial statements should be read in connection with the consolidated financial statements and notes thereto included in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2013.

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 an approximate 0.03% general partner interest in LRLP.

Significant information regarding rights of unitholders 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 LRGPLLC 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 liquidation, after making required payments to Legacy's preferred unitholders, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and LRGPLLC 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 (West Texas and Southeast New Mexico), Mid-Continent and Rocky Mountain regions of the United States.

(b) Accrued Oil and Natural Gas Liabilities

Below are the components of accrued oil and natural gas liabilities as of June 30, 2014 and December 31, 2013.

	June 30, 2014	December 31, 2013
	(In thousands)	
Revenue payable	$30,401	$21,686
Accrued lease operating expense	15,567	11,914
Accrued capital expenditures	16,662	10,409
Accrued ad valorem tax	10,708	9,459
Other	10,258	9,693
	$83,596	$63,161

(c) Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. ("ASU") 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. Legacy is currently evaluating the provisions of ASU 2014-08 and assessing the impact, if any, it may have on its financial position and results of operations.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP.

The standard is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). Legacy is currently evaluating the impact of its pending adoption of ASU 2014-09 on its consolidated financial statements and has not yet determined the method by which it will adopt the standard in 2017.

(2) Long-Term Debt

Long-term debt consists of the following as of June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(In thousands)	
Credit Facility due 2019	$325,000	$348,000
8% Senior Notes due 2020	300,000	300,000
6.625% Senior Notes due 2021	550,000	250,000
	1,175,000	898,000
Unamortized discount on Senior Notes	(21,313)	(19,307)
Total Long-Term Debt	$1,153,687	$878,693

Credit Facility

Previous Credit Agreement: On March 10, 2011, Legacy entered into a five-year $1 billion secured revolving credit facility (as amended, the "Previous Credit Agreement"). Borrowings under the Credit Agreement were set to mature on March 10, 2016.

Current Credit Agreement: On April 1, 2014, Legacy entered into a five-year $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, Compass Bank, as syndication agent, UBS Securities LLC and U.S. Bank National Association, as co-documentation agents and the lenders party thereto (the “Current Credit Agreement”). Borrowings under the Current Credit Agreement mature on April 1, 2019. Legacy's obligations under the Current Credit Agreement are secured by mortgages on over 80% of the total value of its oil and natural gas properties as well as a pledge of all of its ownership interests in its operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base and contains a $2 million sub-limit for letters of credit. The borrowing base is currently set at $950 million. The borrowing base is subject to semi-annual redeterminations on April 1 and October 1 of each year, commencing October 1, 2014. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. Legacy also has the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base then in effect. Any increase in the borrowing base requires the consent of all the lenders and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement. If the requisite 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 Current Credit Agreement so long as it does not increase the borrowing base then in effect.

The Current Credit Agreement contains various covenants that limit Legacy's ability to: (i) incur indebtedness, (ii) enter into certain leases, (iii) grant certain liens, (iv) enter into certain swaps, (v) make certain loans, acquisitions, capital expenditures and investments, (vi) make distributions other than from available cash, (vii) merge, consolidate or allow any material change in the character of its business and (viii) engage in certain asset dispositions, including a sale of all or substantially all of its assets. The Current Credit Agreement also contains covenants that, among other things, require Legacy to maintain specified ratios or conditions as follows: (i) total debt to EBITDA of not more than 4.5 to 1.0 through June 15, 2015 and 4.0 to 1.0 thereafter, (ii) 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 FASB Accounting Standards Codification 815, which includes the current portion of oil, natural gas and interest rate derivatives and (iii) specified minimum levels of natural gas hedges for each fiscal year.

As of June 30, 2014, Legacy had approximately $325 million drawn under the Current Credit Agreement at a weighted-average interest rate of 1.66%, leaving approximately $624.9 million of availability under the Current Credit Agreement. For the six-month period ended June 30, 2014, Legacy paid in cash $3.5 million of interest expense on both the Previous and Current Credit Agreements.

At June 30, 2014, Legacy was in compliance with all covenants of the Credit Agreement.

8% Senior Notes Due 2020

On December 4, 2012, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $300 million of our 8% Senior Notes due 2020 (the "2020 Senior Notes"), which were subsequently registered through a public exchange offer that closed on January 8, 2014. The 2020 Senior Notes were issued at 97.848% of par.
Legacy will have the option to redeem the 2020 Senior Notes, in whole or in part, at any time on or after December 1, 2016, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on December 1 of the years indicated below.

Year	Percentage

2016	104.000	%
2017	102.000	%
2018 and thereafter	100.000	%

Prior to December 1, 2016, Legacy may redeem all or any part of the 2020 Senior Notes at the “make-whole” redemption price as defined in the indenture. In addition, prior to December 1, 2015, Legacy may at its option, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes at the redemption price of 108% with the net proceeds of a public or private equity offering. Legacy may be required to offer to repurchase the 2020 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Legacy's and Legacy Reserves Finance Corporation's obligations under the 2020 Senior Notes are guaranteed by its 100% owned subsidiaries Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc., which constitute all of Legacy's wholly-owned subsidiaries other than Legacy Reserves Finance Corporation. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the properties of the guarantor; (ii) in connection with any sale or other disposition of sufficient capital stock of the guarantor so that it no longer qualifies as our Restricted Subsidiary (as defined in the indenture); (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of the guarantor provided no default or event of default has occurred or is occurring; (vi) at such time the guarantor does not have outstanding guarantees of its, or any other guarantor's, other, debt; or (vii) upon merging into, or transferring all of its properties to Legacy or another guarantor and ceasing to exist. Refer to Note 11 - Subsidiary Guarantors for further details on Legacy's guarantors.

The indenture governing the 2020 Senior Notes limits Legacy's ability and the ability of certain of its subsidiaries to (i) sell assets; (ii) pay distributions on, repurchase or redeem equity interests or purchase or redeem Legacy's subordinated debt, provided that such subsidiaries may pay dividends to the holders of their equity interests (including Legacy) and Legacy may pay distributions to the holders of its equity interests subject to the absence of certain defaults, the satisfaction of a fixed charge coverage ratio test and so long as the amount of such distributions does not exceed the sum of available cash (as defined in the partnership agreement) at Legacy, net proceeds from the sales of certain securities and return of or reductions to capital from restricted investments; (iii) make certain investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from certain of its subsidiaries to Legacy; (vii) consolidate, merge or transfer all or substantially all of Legacy's assets; (viii) engage in certain transactions with affiliates; (ix) create unrestricted subsidiaries; and (x) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2020 Senior Notes are rated investment grade by each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and Legacy and its subsidiaries will cease to be subject to such covenants. The indenture also includes customary events of default. The Partnership is in compliance with all financial and other covenants of the 2020 Senior Notes.

Interest is payable on June 1 and December 1 of each year.

6.625% Senior Notes Due 2021

On May 28, 2013, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $250 million of our 6.625% Senior Notes due 2021 (the "2021 Senior Notes"), which were subsequently registered through a public exchange offer that closed on March 18, 2014. The 2021 Senior Notes were issued at 98.405% of par.

On May 13, 2014, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of an additional $300 million of the 6.625% 2021 Senior Notes. These 2021 Senior Notes were issued at 99.0% of par.

The terms of the 2021 Senior Notes, including details related to our guarantors, are substantially identical to the terms of the 2020 Senior Notes with the exception of the interest rate and redemption provisions noted below. Legacy will have the option to redeem the 2021 Senior Notes, in whole or in part, at any time on or after June 1, 2017, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on June 1 of the years indicated below.

Year	Percentage	
2017	103.313	%
2018	101.656	%
2019 and thereafter	100.000	%

Prior to June 1, 2017, Legacy may redeem all or any part of the 2021 Senior Notes at the “make-whole” redemption price as defined in the indenture. In addition, prior to June 1, 2016, Legacy may at its option, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes at the redemption price of 106.625% with the net proceeds of a public or private equity offering. Legacy may be required to offer to repurchase the 2021 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. The Partnership is in compliance with all financial and other covenants of the 2021 Senior Notes. Interest is payable on June 1 and December 1 of each year.

(3) Acquisitions

On June 4, 2014, Legacy purchased a non-operated interest in oil and natural gas properties located in the Piceance Basin in Garfield County, Colorado from WPX Energy Rocky Mountain, LLC , a subsidiary of WPX Energy, Inc., (the "WPX Acquisition") for a net purchase price of $360.0 million. Consideration included both cash and 300,000 Incentive Distribution Units representing limited partner interests in the Partnership (the "Incentive Distribution Units"), 100,000 of which vested immediately and the remainder of which are available to vest and also subject to forfeiture pursuant to the terms of a related Incentive Distribution Unitholder Agreement. This acquisition was accounted for as a business combination. The fully vested Incentive Distribution Units have been reflected in the financial statements at their estimated issuance date fair value of $30.8 million. No value has been ascribed to the unvested Incentive Distribution Units. During the six month period ended June 30, 2014, Legacy incurred acquisition costs, recorded in general and administrative expense, of approximately $4.9 million related to the WPX Acquisition and other recent acquisitions.

The allocation of the WPX Acquisition purchase price to the fair value of the acquired assets and liabilities assumed was as follows (in thousands):

Proved oil and natural gas properties including related equipment	$403,980
Total assets	403,980
Future abandonment costs	(43,989)
Fair value of net assets acquired	$359,991

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the WPX Acquisition had occurred on January 1, 2013. The pro forma amounts are not necessarily indicative of the results that may be reported in the future and do not include any adjustments for acquisition related expenses.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Revenues	$153,518	$136,016	$301,270	$259,697
Net income (loss) attributable to unitholders	$(21,722)	$21,062	$(16,091)	$11,109
Income (loss) per unit — basic and diluted	$(0.38)	$0.37	$(0.28)	$0.19
Units used in computing income (loss) per unit:				
Basic	57,372	57,246	57,341	57,162
Diluted	57,372	57,349	57,341	57,195

The amounts of revenues and revenues in excess of direct operating expenses included in our consolidated statements of operations for the WPX Acquisition are shown in the table that follows. Direct operating expenses include lease operating expenses and production and other taxes.

	Three Months Ended June 30, 2014	Six Months Ended June 30, 2014
	(In thousands)	
Revenues	$7,316	$7,316
Excess of revenues over direct operating expenses	$4,552	$4,552

(4) Related Party Transactions

Cary D. Brown, Chairman, President and Chief Executive Officer of LRGPLLC, Kyle A. McGraw, Director and Executive Vice President and Chief Development Officer of LRGPLLC and Dale Brown, Director of LRGPLLC, own interests in partnerships which, in turn, own a combined non-controlling 4.12% interest as limited partners in a partnership which owns the building that Legacy occupies. Monthly rent is $58,995, without respect to property taxes and insurance. The lease expires in September 2015.

During the year ended December 31, 2012, Legacy acquired a 5% working interest in prospective Cline Shale acreage from FireWheel Energy, LLC ("FireWheel"), the operator of the properties, for $7.2 million. During the year ended December 31, 2013, Legacy acquired a 5% working interest in additional acreage from Firewheel for $1.2 million. FireWheel is a private-equity funded oil and natural gas exploration company in which Alan Brown, son of Dale Brown, a director of Legacy, and brother of Cary D. Brown, is a principal. The interests acquired by Legacy were marketed to numerous industry participants and are governed by an industry standard Participation Agreement and Joint Operating Agreement.

(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 could have a potential material adverse effect on its financial condition, results of operations or cash flows.

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, respectively.

(6) Fair Value Measurements

As defined in Financial Accounting Standards Board ("FASB") ASC 820-10, 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. ASC 820-10 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1:	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Legacy considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
Level 2:	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that Legacy values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or are 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 collars and interest rate swaps as well as long-term incentive plan liabilities calculated using the Black-Scholes model to estimate the fair value as of the measurement date.
Level 3:	Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e. supported by little or no market activity). Legacy's valuation models are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Legacy does not currently have any instruments classified as Level 3.

As required by ASC 820-10, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Legacy's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy Legacy's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014:

Description	Fair Value Measurements at June 30, 2014 Using 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, 2014
	(In thousands)			
LTIP liability (a)	$—	$(1,616)	$—	$(1,616)
Oil and natural gas commodity derivatives	—	(20,026)	—	(20,026)
Interest rate swaps	—	(3,332)	—	(3,332)

Total	$—	$(24,974)	$—	$(24,974)

(a) See Note 10 for further discussion on unit-based compensation expenses and the related Long-Term Incentive Plan ("LTIP") liability for certain grants accounted for under the liability method.

Legacy estimates the fair values of the swaps based on published forward commodity price curves for the underlying commodities as of the date of the estimate for those commodities for which published forward pricing is readily available. For those commodity derivatives for which forward commodity price curves are not readily available, Legacy estimates, with the assistance of third-party pricing experts, the forward curves as of the date of the estimate. Legacy validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming, where applicable, that those securities trade in active markets. Legacy estimates the option value of puts and calls combined into hedges, including three-way collars and enhanced swaps using an option pricing model which takes into account market volatility, market prices, contract parameters and discount rates based on published LIBOR rates and interest swap rates. In order to estimate the fair value of our interest rate swaps, Legacy uses a yield curve based on money market rates and interest rate swaps, extrapolates a forecast of future interest rates, estimates each future cash flow, derives discount factors to value the fixed and floating rate cash flows of each swap, and then discounts to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available money market rates and interest swap market data. The determination of the fair values above incorporates various factors including the impact of our non-performance risk and the credit standing of the counterparties involved in the Partnership’s derivative contracts. The risk of nonperformance by the Partnership’s counterparties is mitigated by the fact that such current counterparties (or their affiliates) are also current or former bank lenders under the Partnership’s revolving credit facility. In addition, Legacy routinely monitors the creditworthiness of its counterparties. As the factors described above are based on significant assumptions made by management, these assumptions are the most sensitive to change.

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,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Beginning balance	$14,552	$18,814	$20,615	$29,966
Transfers(a)	(14,552)	—	(14,552)	—
Total losses	—	13,534	(6,740)	6,313
Settlements, net	—	38	677	(3,893)
Ending balance	$—	$32,386	$—	$32,386
Losses included in earnings relating to derivatives still held as of June 30, 2014 and 2013	$—	$13,572	$—	$2,420

(a) As part of a routine review of accounting policies and practices, Legacy reviewed the assumptions and inputs used to value its derivative instruments and determined the material inputs (such as quoted market prices and oil and natural gas volatility) for its commodity derivatives more accurately correlate to the description of Level 2 instruments. As such, all instruments previously classified as Level 3 (oil and natural gas collars, swaptions and natural gas swaps for those derivatives indexed to the West Texas Waha, ANR-Oklahoma and CIG Indices) have been transferred to Level 2 instruments.

During periods of market disruption, including periods of volatile oil and natural gas prices, rapid credit contraction or illiquidity, it may be difficult to value certain of the Partnership's derivative instruments if trading becomes less frequent and/or
market data becomes less observable. There may be certain asset classes that were previously in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, more derivative instruments may fall to Level 3 and thus require more subjectivity and management judgment. As such, valuations may include inputs and assumptions that are less observable or require greater estimation as well as valuation methods which are more sophisticated or require greater estimation thereby resulting in valuations with less certainty. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our consolidated financial statements and the period-to-period

changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition

Fair Value on a Non-Recurring Basis

Nonfinancial assets and liabilities measured at fair value on a non-recurring basis include certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; measurements of oil and natural gas property impairments; and the initial recognition of asset retirement obligations ("ARO") for which fair value is used. These ARO estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Legacy has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of Legacy’s asset retirement obligation is presented in Note 8.

Assets measured at fair value during the six-month period ended June 30, 2014 include:

	Fair Value Measurements at June 30, 2014 Using		
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(In thousands)		
Assets:			
Impairment (a)	$—	$—	$3,385
Acquisitions (b)	$—	$—	$476,108

(a) Legacy reviews oil and natural gas properties for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management’s expectations of future oil and natural gas prices. These future price scenarios reflect Legacy’s estimation of future price volatility. During the six-month period ended June 30, 2014, Legacy incurred impairment charges of $3.8 million as oil and natural gas properties with a net cost basis of $7.2 million were written down to their fair value of $3.4 million. In order to determine fair value, Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management’s expectations of future oil and natural gas prices. These future price scenarios reflect Legacy’s estimation of future price volatility. If the net capitalized cost exceeds the undiscounted future net cash flows, Legacy writes the net cost basis down to the discounted future net cash flows, which is management's estimate of fair value. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. The inputs used by management for the fair value measurements utilized in this review include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

(b) Assets and liabilities acquired in a business combination are recorded at fair value. During the six-month period ended June 30, 2014, Legacy acquired oil and natural gas properties, inclusive of unproved acreage acquisitions, with a fair value of $476.1 million in the WPX Acquisition and 5 individually immaterial transactions. Properties acquired are recorded at fair value, which correlates to the discounted future net cash flow. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. For acquired unproved properties, the market-based weighted average cost of capital rate is subjected to additional project specific risking factors. The inputs used by management for the fair value measurements of these acquired oil and natural gas properties include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

The carrying amount of the revolving long-term debt of $325 million as of June 30, 2014 approximates fair value because Legacy's current borrowing rate does not materially differ from market rates for similar bank borrowings. Legacy has classified the revolving long-term debt as a Level 2 item within the fair value hierarchy. As of June 30, 2014, the fair values of the 2020 Senior Notes and the 2021 Senior Notes were $323.6 million and $562.0 million, respectively. As these valuations are based on unadjusted quoted prices in an active market, the fair values are classified as Level 1 items within the fair value hierarchy.

During the period ended June 30, 2014, Legacy issued 100,000 Incentive Distribution Units to WPX Energy Rocky Mountains, LLC in conjunction with the WPX Acquisition. As these Incentive Distribution Units have no active market, Legacy utilized a Monte Carlo simulation to determine their fair value as of the date of issuance. Significant inputs used used in the Monte Carlo simulation included estimates of future distribution growth, unit price, acquisition activity and a market-based weighted average cost of capital rate. As these inputs are unobservable, their value related to the Incentive Distribution Units is classified as Level 3.

(7) Derivative Financial Instruments

Commodity derivative transactions

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps, enhanced 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 from price fluctuations. While the use of these arrangements limits Legacy's ability to benefit from increases in the prices 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. Each of these instruments was a costless contract with no upfront premium paid or payable to our counterparty.

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

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

The following table sets forth a reconciliation of the changes in fair value of Legacy's commodity derivatives for the three and six months ended June 30, 2014 and 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Beginning fair value of commodity derivatives	$5,397	$8,508	$17,673	$24,148
Total gain (loss) - oil derivatives	(33,770)	19,704	(46,030)	12,208
Total gain (loss) - natural gas derivatives	2,337	5,626	(1,289)	117
Crude oil derivative cash settlements paid	6,244	1,934	8,800	1,705
Natural gas derivative cash settlements paid (received)	(234)	(584)	820	(2,990)
Ending fair value of commodity derivatives	$(20,026)	$35,188	$(20,026)	$35,188

Certain of our commodity derivatives and interest rate derivatives are presented on a net basis on the Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our Consolidated Balance Sheets as of the dates indicated below (in thousands):

	June 30, 2014		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:		(In thousands)	
Commodity derivatives	$28,896	$(24,915)	$3,981
Interest rate derivatives	—	—	—
Total derivative assets	$28,896	$(24,915)	$3,981
Offsetting Derivative Liabilities:			
Commodity derivatives	$(48,922)	$24,915	$(24,007)
Interest rate derivatives	(3,332)	—	(3,332)
Total derivative liabilities	$(52,254)	$24,915	$(27,339)

	December 31, 2013		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:		(In thousands)	
Commodity derivatives	$46,356	$(21,263)	$25,093
Interest rate derivatives	—	—	—
Total derivative assets	$46,356	$(21,263)	$25,093
Offsetting Derivative Liabilities:			
Commodity derivatives	$(28,683)	$21,263	$(7,420)
Interest rate derivatives	(4,759)	—	(4,759)
Total derivative liabilities	$(33,442)	$21,263	$(12,179)

As of June 30, 2014, Legacy had the following NYMEX West Texas Intermediate ("WTI") 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 2014	1,599,902	$93.58	$87.50 - $101.50
2015	1,056,301	$93.93	$88.50 - $100.20
2016	228,600	$87.94	$86.30 - $99.85
2017	182,500	$84.75	$84.75

As of June 30, 2014, Legacy had the following NYMEX WTI crude oil derivative three-way collar contracts that combine a long put, a short put and a short call as indicated below:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
July-December 2014	404,800	$71.59	$96.59	$110.71
2015	1,362,800	$65.08	$89.69	$111.84
2016	621,300	$63.37	$88.37	$106.40
2017	72,400	$60.00	$85.00	$104.20

As of June 30, 2014, Legacy had the following NYMEX WTI crude oil enhanced swap contracts that combine a short put, a long put and a fixed-price swap as indicated below:

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2015	365,000	$60.00	$80.00	$92.35
2016	183,000	$57.00	$82.00	$91.70
2017	182,500	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

As of June 30, 2014, Legacy had the following NYMEX WTI crude oil enhanced swap contracts that combine a short put and a fixed-price swap as indicated below:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Swap Price per Bbl
2015	503,000	$74.12	$93.09

As of June 30, 2014, Legacy had the following NYMEX West Texas Waha, ANR-OK and CIG-Rockies 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 2014	12,625,262	$4.64	$3.61 - $6.47
2015	16,219,300	$4.45	$4.15 - $5.82
2016	1,419,200	$4.30	$4.12 - $5.30

As of June 30, 2014, Legacy had the following NYMEX Henry Hub natural gas derivative three-way collar contracts that combine a long put, a short put and a short call as indicated below:

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
July-December 2014	240,000	$4.00	$4.65	$5.03
2015	8,040,000	$3.66	$4.21	$5.01
2016	5,520,000	$3.75	$4.25	$5.08
2017	4,800,000	$3.75	$4.25	$5.54

As of June 30, 2014, Legacy had the following Henry Hub NYMEX to Northwest Pipeline natural gas differential swaps paying a floating differential and receiving a fixed differential 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 2014	4,200,000	$(0.12)	$(0.12)		
2015	9,600,000	$(0.13)	$(0.13)	-	$(0.14)

Interest rate derivative transactions

Due to the volatility of interest rates, Legacy periodically enters into interest rate risk management transactions in the form of interest rate swaps for a portion of its outstanding debt balance. These transactions allow Legacy to reduce exposure to interest rate fluctuations. While the use of these arrangements limits Legacy's ability to benefit from decreases in interest rates, it also reduces Legacy's potential exposure to increases in interest rates. Legacy's arrangements, to the extent it enters into any, apply to only a portion of its outstanding debt balance, provide only partial protection against interest rate increases and limit Legacy's potential savings from future interest rate declines. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Conditions sometimes arise where actual borrowings are less than notional amounts hedged, which has, and could result in overhedged amounts.

Legacy accounts for these interest rate swaps at fair market value and included in the consolidated balance sheet as assets or liabilities.

Legacy does not 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 as a component of interest expense. The total impact on interest expense from the mark-to-market and settlements was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Beginning fair value of interest rate swaps	$(4,047)	$(8,102)	$(4,759)	$(9,547)
Total gain (loss) on interest rate swaps	(109)	55	(283)	(281)
Cash settlements paid	824	1,569	1,710	3,350
Ending fair value of interest rate swaps	$(3,332)	$(6,478)	$(3,332)	$(6,478)

The table below summarizes the interest rate swap position as of June 30, 2014:

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at June 30, 2014
(Dollars in thousands)				
$29,000	3.070 %	10/16/2007	10/16/2015	$(988)
$13,000	3.112 %	11/16/2007	11/16/2015	(479)
$12,000	3.131 %	11/28/2007	11/28/2015	(443)
$50,000	0.710 %	8/10/2011	8/10/2014	(47)
$50,000	0.702 %	8/10/2011	8/10/2014	(46)
$50,000	2.500 %	10/10/2008	10/10/2015	(1,329)
Total fair market value of interest rate derivatives				$(3,332)

(8) Asset Retirement Obligation

AROs associated with the retirement of a tangible long-lived asset are 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 six months ended June 30, 2014 and year ended December 31, 2013:

	June 30, 2014	December 31, 2013
	(In thousands)	
Asset retirement obligation - beginning of period	$175,786	$162,183
Liabilities incurred with properties acquired	48,230	10,969
Liabilities incurred with properties drilled	—	494
Liabilities settled during the period	(1,876)	(2,441)
Liabilities associated with properties sold	(3,641)	(1,606)
Current period accretion	3,299	6,187
Asset retirement obligation - end of period	$221,798	$175,786

(9) Partners' Equity

Preferred Units

On April 17, 2014, Legacy issued 2,000,000 of its 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") in a public offering at a price of $25.00 per unit. On May 12, 2014 Legacy issued an additional 300,000 of our Series A Preferred Units pursuant to the underwriters' option to purchase additional Series A Preferred Units. Legacy received aggregate net proceeds of approximately $55.2 million, after deducting underwriting discounts and estimated offering expenses, from the offering of Series A Preferred Units during the three-months ended June 30, 2014.

On June 17, 2014, Legacy issued 7,000,000 of its 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units") in a public offering at a price of $25.00 per unit. Legacy received aggregate net proceeds of approximately $169.1 million, after deducting underwriting discounts and estimated offering expenses, from the offering of Series B Preferred Units during the three-months ended June 30, 2014.

Distributions on the Series A Preferred Units and Series B Preferred Units (collectively, the "Preferred Units") are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of the Partnership's general partner. Distributions on the Series A Preferred Units will be payable from, and including, the date of the original issuance to, but not including April 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions on the Series B Preferred Units will be payable from, and including, the date of the original issuance to, but not including June 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions accruing on and after April 15, 2024 for the Series A Preferred Units and June 15, 2024 for the Series B Preferred Units will accrue at an annual rate equal to the sum of (a) three-month LIBOR as calculated on each applicable date of determination and (b) 5.24% for Series A and 5.26% for Series B, based on the $25.00 liquidation preference per preferred unit.

At any time on or after April 15, 2019 or June 15, 2019, Legacy may redeem the Series A Preferred Units or Series B Preferred Units, respectively, in whole or in part at a redemption price of $25.00 per Preferred Unit plus an amount equal to all accumulated and unpaid distributions thereon through and including the date of redemption, whether or not declared. Legacy may also redeem the Preferred Units in the event of a Change of Control.

The Series A Preferred Units and the Series B Preferred Units trade on NASDAQ under the symbols "LGCYP" and "LGCYO," respectively.

Incentive Distribution Units

On June 4, 2014, Legacy issued 300,000 Incentive Distribution Units to WPX Energy Rocky Mountain, LLC ("WPX") as part of the WPX Acquisition. The Incentive Distribution Units issued to WPX include 100,000 Incentive Distribution Units that immediately vested along with the ability to vest in up to an additional 200,000 Incentive Distribution Units (the "Unvested IDUs") in connection with any future asset sales or transactions completed with Legacy. Incentive Distribution Units that are not issued to WPX or other parties will remain in Legacy's treasury for the benefit of all limited partners until such time as Legacy may make future issuances of Incentive Distribution Units.

The Incentive Distribution Units represent a right to incremental cash distributions from Legacy after certain target levels of distributions are paid to unitholders, which targets are set above the current levels of Legacy's distributions to unitholders. The Unvested IDUs do not participate in cash distributions from Legacy until vested. The Unvested IDUs will automatically be forfeited on each of the first two anniversaries of the closing date of the WPX Acquisition in an amount per forfeiture equal to 66,666 Incentive Distribution Units and on the third anniversary of the closing date of the WPX Acquisition in an amount equal to 66,668 Incentive Distribution Units. Unvested IDUs that have not been forfeited will vest ratably at a rate of 10,000 Incentive Distribution Units per $35.5 million of additional cash consideration that is paid by Legacy to WPX or to a third party (along with the fair market value of any non-cash consideration) in connection with the consummation of any transaction by which Legacy acquires oil and natural gas properties (or rights therein or other assets related thereto) from WPX or jointly with WPX and such third party.

In addition, the vested and outstanding Incentive Distribution Units held by WPX may be converted by Legacy, subject to applicable conversion factors, into units on a one-for-one basis at any time when Legacy has made a distribution in respect of its units for each of the four full fiscal quarters prior to the delivery of its conversion notice, and the amount of the distribution in respect of the units for the full quarter immediately preceding delivery of its conversion notice was equal to at least $0.90 per unit; and the amount of all distributions during each quarter within the four-quarter period immediately preceding delivery of its conversion notice did not exceed the adjusted operating surplus for such quarter. Further, WPX also has the ability to similarly convert any of its vested Incentive Distribution Units beginning three years after June 4, 2014. WPX may not transfer any of the Incentive Distribution Units it holds to any person that is not a controlled affiliate of WPX.

Income (loss) per unit

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Income (loss) available to unitholders	$(18,682)	$21,754	$(18,154)	$15,049
Weighted average number of units outstanding	57,372	57,246	57,341	57,162
Effect of dilutive securities:				
Restricted and phantom units	—	103	—	33
Weighted average units and potential units outstanding	57,372	57,349	57,341	57,195
Basic and diluted income (loss) per unit	$(0.33)	$0.38	$(0.32)	$0.26

For the three and six months ended June 30, 2014, 264,097 restricted units and 323,965 phantom units, respectively, were excluded from the calculation of diluted income per unit due to their anti-dilutive effect. For the three and six months ended June 30, 2013, 321,866 and 391,663 restricted units and phantom units, respectively, were excluded from the calculation of diluted income per unit due to their anti-dilutive effect.

(10) Unit-Based Compensation

Long-Term Incentive Plan

On March 15, 2006, the LTIP for Legacy was implemented 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 ("UARs"). The LTIP permits the grant of awards that may be made or settled in units to an aggregate of 2,000,000 units. As of June 30, 2014, grants of awards net of forfeitures and, in the case of phantom units, historical exercises covering 1,255,721 units had been made, comprised of 266,014 unit option awards, 535,364 restricted unit awards, 323,965 phantom unit awards and 130,378 unit awards. The UAR awards granted under the LTIP may only be settled in cash, and therefore are not included in the aggregate number of units granted under the LTIP. The LTIP is administered by the compensation committee (the “Compensation Committee”) of the board of directors of LRGPLLC.

The cost of employee services in exchange for an award of equity instruments is measured 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. However, if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if an 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. Due to Legacy’s historical practice of settling options, UARs and certain phantom unit awards in cash, Legacy accounted for unit options, UARs and certain phantom unit awards by utilizing the liability method. 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 each reporting period. Compensation cost is recognized based on the change in the liability between periods. However, during 2013, the Compensation Committee revised the executive compensation policy and amended certain historical phantom unit award agreements to eliminate the Compensation Committee's option of settling phantom unit awards for executive officers in cash. Due to the elimination of the cash settlement option, Legacy now accounts for executive phantom unit awards under the equity method as described in ASC 718. Legacy treated the amendment as a cancellation of the historical awards and a grant of new awards in the period, though the award amounts and vesting terms remained unchanged.

Unit Appreciation Rights and Unit Options

A UAR is a notional unit that entitles the holder, upon vesting, to receive cash valued at the difference between the closing price of units on the exercise date and the exercise price, as determined on the date of grant. Because these awards are settled in cash, Legacy is accounting for the UARs by utilizing the liability method.

During the year ended December 31, 2013, Legacy issued 156,650 UARs to employees which vest ratably over a three-year period and 77,506 UARs to employees which vest at the end of a three-year period. During the six-month period ended June 30, 2014, Legacy issued 61,500 UARs to employees which vest ratably over a three-year period. All UARs granted in 2013 and 2014 expire seven years from the grant date and are exercisable when they vest.

For the six-month periods ended June 30, 2014 and 2013, Legacy recorded \$0.3 million and \$0.5 million, respectively, of compensation expense (benefit) due to the change in liability from December 31, 2013 and 2012, respectively, based on its use of the Black-Scholes model to estimate the June 30, 2014 and 2013 fair value of these UARs and unit options (see Note 6). As of June 30, 2014, there was a total of approximately $1.5 million of unrecognized compensation costs related to the unexercised and non-vested portion of these UARs. At June 30, 2014, this cost was expected to be recognized over a weighted-average period of approximately 2.11 years. Compensation expense is based upon the fair value as of June 30, 2014 and is recognized as a percentage of the service period satisfied. Based on historical data, Legacy has assumed a volatility factor of approximately 42% and employed the Black-Scholes model to estimate the June 30, 2014 fair value to be realized as compensation cost based on the percentage of service period satisfied. Based on historical data, Legacy has assumed an estimated forfeiture rate of 4.2%. Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.38 per unit.

A summary of UAR and unit option activity for the six months ended June 30, 2014 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2014	627,043	$ 25.99		
Granted	61,500	27.77		
Exercised	(125,584)	24.11		
Forfeited	(20,835)	26.20		
Outstanding at June 30, 2014	542,124	$ 26.62	5.5	$2,511,421
Options and UARs exercisable at June 30, 2014	159,955	$ 24.95	3.7	$1,013,017

The following table summarizes the status of Legacy’s non-vested UARs since January 1, 2014:

	Non-Vested UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2014	386,755	$ 27.21
Granted	61,500	27.77
Vested	(46,251)	27.16
Forfeited	(19,835)	27.01
Non-vested at June 30, 2014	382,169	$ 27.32

Legacy has used a weighted-average risk-free interest rate of 1.6% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at June 30, 2014 whose terms are consistent with the expected life of the UARs and unit options. Expected life represents the period of time that UARs and unit options are expected to be outstanding and is based on Legacy’s best estimate. The following table represents the weighted-average assumptions used for the Black-Scholes option-pricing model.

	Six Months Ended June 30, 2014
Expected life (years)	5.52
Risk free interest rate	1.6 %
Annual distribution rate per unit	$2.38
Volatility	42 %

Phantom Units

Legacy has also issued phantom units under the LTIP to both executive officers, as described below, and certain other employees. A phantom unit is a notional unit that entitles the holder, upon vesting, to receive, in the case of non-executive

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employees, cash valued at the closing price of units on the vesting date, or, at the discretion of the Compensation Committee, the same number of Partnership units. Because Legacy's current intent is to settle these non-executive phantom unit awards in cash, Legacy is accounting for these phantom units by utilizing the liability method. As mentioned above, in the case of executive employees, the Compensation Committee revised the historical grants for all executive phantom units to eliminate any election for cash payment. As these awards can now only be settled in Partnership units, Legacy is accounting for these phantom units by utilizing the equity method.

On September 21, 2009, the board of directors of LRGPLLC, upon the recommendation of the Compensation Committee, implemented an equity-based incentive compensation policy applicable to the executive officers of Legacy. In addition to cash bonus awards, under the compensation plan, the executives are eligible for both subjective and objective grants of phantom units. The subjective, or service-based, grants may be awarded up to a maximum percentage of annual salary as determined by the Compensation Committee. Once granted, these phantom units vest ratably over a three-year period. The objective, or performance-based, grants may be awarded up to a maximum percentage of annual salary as determined by the Compensation Committee. However, the amount to vest each year for the three-year vesting period will be determined on each vesting date based on a three-step process, with the first two steps each comprising 50% of the total vesting amount while the third step is the sum of the first two steps. The first step in the process will be a function of Total Unitholder Return ("TUR") for the Partnership and the percentage rank of the Legacy TUR among a peer group of upstream master limited partnerships, as determined by the Compensation Committee at the beginning of each year. In the second step, the Legacy TUR will be compared to the TUR of a group of master limited partnerships included in the Alerian MLP Index. The third step is the addition of the above two steps to determine the total performance-based awards to vest. On March 7, 2013, the board of directors of LRGPLLC, upon the recommendation of the Compensation Committee, approved a revised compensation policy (the "Revised Policy.") This Revised Policy applies to incentive awards granted after the fiscal year ended 2013. While the Revised Policy measures TUR against both the peer group and Alerian MLP Index, the measurement periods were increased to a three-year cumulative measurement period with a corresponding increase in vesting from a ratable three-year vesting to three-year cliff vesting. Performance based phantom units subject to vesting which do not vest in a given year will be forfeited. With respect to both the subjective and objective units awarded under both compensation policies, distribution equivalent rights ("DERs") will accumulate and accrue based on the total number of actual amounts vested and will be payable at the date of vesting. However, due to the aforementioned revision for executive employees, accrued DERs paid at the date of vesting will be treated as distributions in the period paid rather than being recognized as compensation expense over the life of the award.

On March 7, 2013, the Compensation Committee approved the award of 46,430 subjective, or service-based, phantom units and 76,723 objective, or performance based, phantom units to Legacy's executive officers. On March 4, 2014, the Compensation Committee approved the award of 117,197 subjective, or service-based, phantom units and 102,572 objective, or performance based, phantom units to Legacy's executive officers.

Compensation expense (benefit) related to the phantom units and associated DERs was $1.0 million and $0.3 million for the six months ended June 30, 2014 and 2013, respectively.

Restricted Units

During the year ended December 31, 2013, Legacy issued an aggregate of 85,728 restricted units to non-executive employees. These restricted units awarded mostly vest ratably over a three-year period all beginning on or around the date of grant. During the six-month period ended June 30, 2014, Legacy issued an aggregate of 106,515 restricted units to non-executive employees. These restricted units awarded vest ratably over a three-year period. Compensation expense related to restricted units was $1.1 million and $1.1 million for the six months ended June 30, 2014 and 2013, respectively. As of June 30, 2014, there was a total of $6.2 million of unrecognized compensation expense related to the unvested portion of these restricted units. At June 30, 2014, this cost was expected to be recognized over a weighted-average period of 2.6 years. Pursuant to the provisions of ASC 718, Legacy’s issued units, as reflected in the accompanying consolidated balance sheet at June 30, 2014, do not include 264,097 units related to unvested restricted unit awards.

Board and Additional Executive Units

On May 14, 2013, Legacy granted and issued 3,715 units to each of its five non-employee directors. The value of each unit was $27.39 at the time of issuance. On May 15, 2014, Legacy granted and issued 3,628 units to each of its five non-employee directors. The value of each unit was $27.50 at the time of issuance.

(11) Subsidiary Guarantors

On April 2, 2014, we filed a registration statement on Form S-3 with the Securities and Exchange Commission ("SEC") to register the issuance and sale of, among other securities, our debt securities, which may be co-issued by Legacy Reserves Finance Corporation. The registration statement also registered guarantees of debt securities by Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc. The Partnership's 2020 Senior Notes were issued in a private offering on December 4, 2012 and were subsequently registered through a public exchange offer that closed on January 8, 2014. The Partnership's 2021 Senior Notes were issued in two separate private offerings on May 28, 2013 and May 8, 2014. $250 million aggregate principal amount of our 2021 Senior Notes were subsequently registered through a public exchange offer that closed on March 18, 2014. The 2020 Senior Notes and the 2021 Senior Notes are guaranteed by our 100% owned subsidiaries Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc., which constitute all of our wholly-owned subsidiaries other than Legacy Reserves Finance Corporation, and certain other future subsidiaries (the “Guarantors”, together with any future 100% owned subsidiaries that guarantee the Partnership's 2020 Senior Notes and 2021 Senior Notes, the “Subsidiaries”). The Subsidiaries are 100% owned by the Partnership and the guarantees by the Subsidiaries are full and unconditional, except for customary release provisions described in Note 2 - Long-Term Debt. The Partnership has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to the Partnership. The guarantees constitute joint and several obligations of the Guarantors.

(12) Subsequent Events

On July 22, 2014, Legacy's board of directors approved a distribution of $0.61 per unit payable on August 14, 2014 to unitholders of record on August 1, 2014, representing an increase of $0.015 per unit over the last quarterly distribution.

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 costs;
- the level of our lease operating expenses, general and administrative costs and finding and development costs, including payments to our general partner;
- the level of capital expenditures;
- the level of cash distributions to our unitholders;
- our future operating results; and
- our plans, objectives, expectations and intentions.

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

The forward-looking statements contained in this document are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this document are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in Legacy's Annual Report on Form 10-K for the year ended December 31, 2013 in Item 1A under "Risk Factors" and Legacy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 in Part II, Item 1A under "Risk Factors." The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly.

Overview

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.

Acquisitions have been financed with a combination of proceeds from bank borrowings, issuance of notes, issuances of units and preferred 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 and our access to capital and the amount of our cash distributions.

We face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. We attempt to overcome this natural decline by acquiring more reserves than we produce, drilling to find additional reserves, utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary (CO_2 and nitrogen) recovery methods to re-pressure the reservoir and recover additional oil, recompleting or adding pay in existing wellbores and improving artificial lift. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on adding reserves through acquisitions and exploitation projects. Our ability to add reserves through acquisitions and development projects is dependent upon many factors including our ability to raise capital, competitively bid on acquisitions, 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 “Investing Activities” below, we have entered into oil and natural gas derivatives designed to mitigate the effects of price fluctuations covering a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our capital investment programs and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact on any redetermination to our borrowing base under our revolving credit facility.

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

Production and Operating Costs Reporting

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

Such costs include, but are not limited to, the cost of electricity to lift produced fluids, chemicals to treat wells, field personnel to monitor the wells, well repair expenses to restore production, well workover expenses intended to increase production, and ad valorem taxes. We incur and separately report severance taxes paid to the states in which our properties are located. These taxes are reported as production taxes and are a percentage of oil and natural gas revenue. Ad valorem taxes are a percentage of property valuation. Gathering and transportation costs are generally borne by the purchasers of our oil and natural gas as the price paid for our products reflects these costs. We do not consider royalties paid to mineral owners an expense as we deduct hydrocarbon volumes owned by mineral owners from the reported hydrocarbon sales volumes.

Operating Data

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$108,731	$97,852	$210,786	$188,209
Natural gas liquids sales	5,103	3,161	9,069	6,503
Natural gas sales	23,280	17,373	43,163	32,553
Total revenue	$137,114	$118,386	$263,018	$227,265
Expenses:				
Oil and natural gas production, excluding ad valorem taxes	$42,056	$34,265	$81,694	$66,650
Ad valorem taxes	$3,753	$2,919	$6,649	$5,885
Total oil and natural gas production	$45,809	$37,184	$88,343	$72,535
Production and other taxes	$8,595	$6,771	$16,550	$13,698
General and administrative, excluding LTIP	$12,669	$5,720	$19,626	$11,017
LTIP expense	$2,140	$1,344	$2,830	$2,329
Total general and administrative	$14,809	$7,064	$22,456	$13,346
Depletion, depreciation, amortization and accretion	$38,537	$39,113	$72,234	$80,765
Commodity derivative cash settlements:				
Oil derivative cash settlements paid	$(6,244)	$(1,934)	$(8,800)	$(1,705)
Natural gas derivative cash settlements received (paid)	$234	$584	$(820)	$2,990
Production:				
Oil (MBbls)	1,175	1,089	2,310	2,203
Natural gas liquids (MGal)	5,519	3,320	8,881	6,213
Natural gas (MMcf)	4,877	3,649	8,102	7,194
Total (MBoe)	2,119	1,776	3,872	3,550
Average daily production (Boe/d)	23,286	19,516	21,392	19,613
Average sales price per unit (excluding derivative cash settlements):				
Oil price (per Bbl)	$92.54	$89.85	$91.25	$85.43
Natural gas liquids price (per Gal)	$0.92	$0.95	$1.02	$1.05
Natural gas price (per Mcf) (a)	$4.77	$4.76	$5.33	$4.53
Combined (per Boe)	$64.71	$66.66	$67.93	$64.02
Average sales price per unit (including derivative cash settlements):				
Oil price (per Bbl)	$87.22	$88.08	$87.44	$84.66
Natural gas liquids price (per Gal)	$0.92	$0.95	$1.02	$1.05
Natural gas price (per Mcf) (a)	$4.82	$4.92	$5.23	$4.94
Combined (per Boe)	$61.87	$65.90	$65.44	$64.38
Average WTI oil spot price (per Bbl)	$103.35	$94.05	$101.05	$94.18
Average Henry Hub natural gas index price (per Mcf)	$4.68	$3.34	$4.81	$3.72
Average unit costs per Boe:				
Oil and natural gas production	$19.85	$19.29	$21.10	$18.77

Ad valorem taxes	$1.77	$1.64	$1.72	$1.66
Production and other taxes	$4.06	$3.81	$4.27	$3.86
General and administrative excluding LTIP	$5.98	$3.22	$5.07	$3.10
Total general and administrative	$6.99	$3.98	$5.80	$3.76
Depletion, depreciation, amortization and accretion	$18.19	$22.02	$18.66	$22.75

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

Results of Operations

Three-Month Period Ended June 30, 2014 Compared to Three-Month Period Ended June 30, 2013

Our revenues from the sale of oil were $108.7 million and $97.9 million for the three-month periods ended June 30, 2014 and 2013, respectively. Our revenues from the sale of NGLs were $5.1 million and $3.2 million for the three-month periods ended June 30, 2014 and 2013, respectively. We had revenues from the sale of natural gas of $23.3 million and $17.4 million for the three-month periods ended June 30, 2014 and 2013, respectively. The $10.9 million increase in oil revenues reflects the increase in oil production of 86 MBbls (8%) as well as an increase in average realized price of $2.69 per Bbl (3%). This increase in production is related to our purchase of additional oil and natural gas properties during the second quarter of 2014, as well as our ongoing development activities. The improvement in realized oil prices of $2.69 per Bbl during the three months ended June 30, 2014 compared to the same period in 2013 was due to an improvement in average West Texas Intermediate ("WTI") crude oil prices of $9.30 per Bbl partially offset by an increase in realized regional differentials, which reduce the price we receive for our oil. The $1.9 million increase in NGL sales reflects an increase in NGL production of 2,199 MGals (66%), primarily due to the WPX Acquisition (1,896 MGals), partially offset by a decrease in the realized NGL price of approximately $0.03 (3%). The $5.9 million increase in natural gas revenues reflects an increase in our production volumes, partially offset by a decrease in realized natural gas prices. Our natural gas production increased by approximately 1,228 MMcf (34%) primarily due to the acquisition of a non-operated interest in oil and natural gas properties located in the Piceance Basin in Garfield County, Colorado from WPX Energy Rocky Mountain, LLC, a subsidiary of WPX Energy, Inc. (the "WPX Acquisition"), which accounted for approximately 1,469 MMcf, partially offset by ordinary natural gas decline. Average realized natural gas prices remained virtually flat, increasing by $0.01 per Mcf (0%) during the three months ended June 30, 2014 compared to the same period in 2013 due to the inclusion of natural gas from the WPX Acquisition, which receives a lower price than NYMEX Henry Hub pricing. We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content contained within those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin are higher than NYMEX Henry Hub natural gas prices due to this NGL content.

For the three-month period ended June 30, 2014, we recorded $31.4 million of net losses on oil and natural gas derivatives. Commodity derivative gains and losses represent the changes in fair value of our commodity derivatives during the period and are based on oil and natural gas futures prices. The net losses recognized during the three-month period ended June 30, 2014 are primarily due to the increase in oil prices during the period. For the three-month period ended June 30, 2013, we recorded $25.3 million of net gains on oil and natural gas derivatives. Settlements of such contracts resulted in cash payments of $6.0 million and $1.4 million during the three months ended June 30, 2014 and 2013, respectively.

Our oil and natural gas production expenses, excluding ad valorem taxes, increased to $42.1 million ($19.85 per Boe) for the three-month period ended June 30, 2014 from $34.3 million ($19.29 per Boe) for the three-month period ended June 30, 2013. Production expenses increased primarily due to expenses associated with our acquisitions including $2.1 million related to the WPX Acquisition as well as development activities and, to a lesser extent, industry-wide cost increases. Our ad valorem tax expense increased marginally to $3.8 million ($1.77 per Boe) for the three-month period ended June 30, 2014 compared to $2.9 million ($1.64 per Boe) for the three-month period ended June 30, 2013 primarily due to increased well counts from recent acquisitions.

Our production and other taxes were $8.6 million and $6.8 million for the three-month periods ended June 30, 2014 and 2013, respectively. Production and other taxes increased because of increased production volumes related to recent acquisitions and increased product prices, as production and other taxes as a percentage of revenue remained relatively unchanged during the three-month period ended June 30, 2014 compared to the same period in 2013.

Our general and administrative expenses were $14.8 million and $7.1 million for the three-month periods ended June 30, 2014 and 2013, respectively. General and administrative expenses increased $7.7 million primarily due $4.9 million of acquisition-related expenses, a $1.7 million increase in salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base and a $0.8 million increase in LTIP expenses due to the increase in unit price during the period.

We incurred depletion, depreciation, amortization and accretion expense, or DD&A, of $38.5 million and $39.1 million for the three-month periods ended June 30, 2014 and 2013, respectively. DD&A decreased due to a decrease in both the depletion rate and depletable basis due to prior year depletion and impairment which reduced the amount available to be depleted. This reduction was partially offset by the WPX Acquisition and other recent acquisitions. As the depletion rate is a function of production and reserves, the increase in our reserves balance due to the WPX Acquisition and other recent acquisitions, combined with only a partial quarter of increased production from the acquisitions, resulted in a lower depletion rate.

Impairment expense was $2.4 million and $20.8 million for the three-month periods ended June 30, 2014 and 2013, respectively. In the three-month period ended June 30, 2014, we recognized $2.4 million of impairment expense on two separate producing fields primarily related to the removal of a proved undeveloped drilling ("PUD") location from a field as recent results from offset developments operated by other producers reduced the viability of development. The removal of this PUD reduced the expected cash flows for this field, resulting in impairment. Impairment expense for the period ended June 30, 2013 was primarily related to higher realized oil and natural gas differentials, which reduced the future expected cash flows.

We recorded interest expense of $16.2 million and $11.2 million for the three-month periods ended June 30, 2014 and 2013, respectively. Interest expense increased approximately $5.0 million primarily due to interest expense related to additional senior notes issued subsequent to June 30, 2013.

Six-Month Period Ended June 30, 2014 Compared to Six-Month Period Ended June 30, 2013

Our revenues from the sale of oil were $210.8 million and $188.2 million for the six-month periods ended June 30, 2014 and 2013, respectively. Our revenues from the sale of NGLs were $9.1 million and $6.5 million for the six-month periods ended June 30, 2014 and 2013, respectively. We had revenues from the sale of natural gas of $43.2 million and $32.6 million for the six-month periods ended June 30, 2014 and 2013, respectively. The $22.6 million increase in oil revenues reflects the increase in oil production of 107 MBbls (5%) as well as an increase in average realized price of $5.82 per Bbl (7%). This increase in production is related to our purchase of additional oil and natural gas properties in recent acquisitions, as well as our ongoing development activities partially offset by a decline in the Lower Abo oil production and downtime related to inclement weather. The improvement in realized oil prices of $5.82 per Bbl during the six months ended June 30, 2014 compared to the same period in 2013 was due to an improvement in average West Texas Intermediate (“WTI”) crude oil prices of $6.87 per Bbl partially offset by increased regional crude oil differentials. The $2.6 million increase in NGL sales reflects an increase in NGL production of 2,668 MGals (43%), primarily due to the WPX Acquisition (1,896 MGals), partially offset by a reduction in realized NGL price of approximately $0.03 (3%). The $10.6 million increase in natural gas revenues reflects an increase in our production volumes as well as an increase in realized natural gas prices. Our natural gas production increased by approximately 908 MMcf (13%) primarily due to the WPX Acquisition (1,469 MMcf) partially offset by declines related to our Lower Abo properties as well as plant and gathering downtime related to inclement weather as well as other gathering issues which reduced the volumes available for sale. Average realized natural gas prices increased by $0.80 per Mcf (18%) during the six months ended June 30, 2014 compared to the same period in 2013, primarily due to the increase in index prices. We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content contained within those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin are higher than NYMEX Henry Hub natural gas prices due to this NGL content.

For the six-month period ended June 30, 2014, we recorded $47.3 million of net losses on oil and natural gas derivatives. Commodity derivative gains and losses represent the changes in fair value of our commodity derivatives during the period and are based on oil and natural gas futures prices. The net losses recognized during the six-month period ended June 30, 2014 are primarily due to the increase in oil prices during the period. For the six-month period ended June 30, 2013, we recorded $12.3 million of net gains on oil and natural gas derivatives. Settlements of such contracts resulted in cash payments of $9.6 million and cash receipts of $1.3 million during the six months ended June 30, 2014 and 2013, respectively.

Our oil and natural gas production expenses, excluding ad valorem taxes, increased to $81.7 million ($21.10 per Boe) for the six-month period ended June 30, 2014 from $66.7 million ($18.77 per Boe) for the six-month period ended June 30, 2013. Production expenses increased primarily due to expenses associated with our acquisitions and development activities as well as a $3.5 million increase in one-time well workover expenses and industry-wide cost increases. Our ad valorem tax expense increased marginally to $6.6 million ($1.72 per Boe) for the six-month period ended June 30, 2014 compared to $5.9 million ($1.66 per Boe) for the six-month period ended June 30, 2013 primarily due to increased well counts from recent acquisitions.

Our production and other taxes were $16.6 million and $13.7 million for the six-month periods ended June 30, 2014 and 2013, respectively. Production and other taxes increased because of increased production volumes related to recent acquisitions and increased product prices, as production and other taxes as a percentage of revenue remained relatively unchanged during the six-month period ended June 30, 2014 compared to the same period in 2013.

Our general and administrative expenses were $22.5 million and $13.3 million for the six-month periods ended June 30, 2014 and 2013, respectively. General and administrative expenses increased $9.1 million primarily due to $4.9 million of acquisition-related expenses, a $3.2 million increase in salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base and a $0.5 million increase in LTIP expenses due to the increase in unit price during the period.

We incurred depletion, depreciation, amortization and accretion expense, or DD&A, of $72.2 million and $80.8 million for the six-month periods ended June 30, 2014 and 2013, respectively. DD&A decreased due to a decrease in both the depletion rate and depletable basis due to prior year depletion and impairment which reduced the amount available to be depleted. This reduction was partially offset by the WPX Acquisition and other recent acquisitions. As the depletion rate is a function of production and reserves, the increase in our reserves balance due to the WPX Acquisition and other recent acquisitions, combined with only a partial quarter of increased production from the acquisitions, resulted in a lower depletion rate.

Impairment expense was $3.8 million and $22.5 million for the six-month periods ended June 30, 2014 and 2013, respectively. In the six-month period ended June 30, 2014, we recognized $3.8 million of impairment expense on four separate producing fields primarily related to a reduction in the future expected cash flows from four unproved properties and the removal of a PUD. We consider expected cash flows from both proved and unproved properties in a given field when reviewing for impairment. In the case of two of the impaired fields, impairment was indicated in previous periods, but the additional cash flow from identified unproved projects mitigated the indicated impairment. During the six months ended June 30, 2014, we revised certain reserve estimates associated with these unproved properties due to other operators' recent drilling results on adjacent properties and thus recognized impairment on the reduced expected cash flows. Impairment expense for the period ended June 30, 2013 was primarily related to higher realized oil and natural gas differentials, which reduced the future expected cash flows.

We recorded interest expense of $30.2 million and $21.9 million for the six-month periods ended June 30, 2014 and 2013, respectively. Interest expense increased approximately $8.3 million primarily due to interest expense related to additional senior notes issued subsequent to June 30, 2013.

Non-GAAP Financial Measure

Our management uses Adjusted EBITDA as a tool to provide additional information and metrics relative to the performance of our business. Our management believes that Adjusted EBITDA is useful to investors because this measure is used by many companies in the industry as a measure of operating and financial performance and is commonly employed by financial analysts and others to evaluate the operating and financial performance of the Partnership from period to period and to compare it with the performance of other publicly traded partnerships within the industry. Adjusted EBITDA may not be comparable to a similarly titled measure of other publicly traded limited partnerships or limited liability companies because all companies may not calculate Adjusted EBITDA in the same manner.

The following presents a reconciliation of “Adjusted EBITDA,” which is a non-GAAP measure, to its nearest comparable GAAP measure. Adjusted EBITDA should not be considered as an alternative to GAAP measures, such as net income, operating income, cash flow from operating activities, or any other GAAP measure of financial performance.

Adjusted EBITDA is defined as net income (loss) plus:

- Interest expense;
- Income taxes;
- Depletion, depreciation, amortization and accretion;
- Impairment of long-lived assets;
- (Gain) loss on sale of partnership investment;
- (Gain) loss on disposal of assets;
- Equity in (income) loss of equity method investees;
- Unit-based compensation expense (benefit) related to LTIP unit awards accounted for under the equity or liability methods;

- Minimum payments earned in excess of overriding royalty interest earned;
- Equity in EBITDA of equity method investee;
- Net (gains) losses on commodity derivatives;
- Net cash settlements received (paid) on commodity derivatives; and
- Transaction expenses related to acquisitions.

The following table presents a reconciliation of our consolidated net income (loss) to Adjusted EBITDA for the three and six months ended June 30, 2014 and 2013, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Net income (loss)	$(16,488)	$21,754	$(15,960)	$15,049
Plus:				
Interest expense	16,225	11,206	30,164	21,898
Income tax expense	278	368	592	578
Depletion, depreciation, amortization and accretion	38,537	39,113	72,234	80,765
Impairment of long-lived assets	2,387	20,774	3,798	22,517
Gain on disposal of assets	(3,853)	(46)	(1,552)	(265)
Equity in income of equity method investees	(191)	(140)	(183)	(185)
Unit-based compensation expense	2,140	1,344	2,830	2,329
Minimum payments earned in excess of overriding royalty interest(a)	341	10	673	410
Equity in EBITDA of equity method investee(b)	241	226	499	226
Net (gains) losses on commodity derivatives	31,433	(25,330)	47,319	(12,325)
Net cash settlements received (paid) on commodity derivatives	(6,010)	$(1,350)	$(9,620)	$1,285
Transaction expenses related to acquisitions	4,911	$—	$4,966	$—
Adjusted EBITDA	$69,951	$67,929	$135,760	$132,282

(a) A portion of minimum payments earned in excess of overriding royalties earned under a contractual agreement expiring December 31, 2019. The remaining amount of the minimum payments are recognized in net income.

(b) EBITDA applicable to equity method investee is defined as the equity method investee's net income plus interest expense and depreciation.

For the three months ended June 30, 2014 and 2013, respectively, Adjusted EBITDA increased 3% to $70.0 million from $67.9 million primarily due to production from the WPX Acquisition and other recent oil and natural gas property acquisitions as well as higher realized commodity prices. These factors were partially offset by higher commodity derivative settlement payments of approximately $4.7 million as well as higher expenses and production taxes.

For the six months ended June 30, 2014 and 2013, respectively, Adjusted EBITDA increased 3% to $135.8 million from $132.3 million primarily due to production from the WPX Acquisition and other recent oil and natural gas property acquisitions as well as higher realized commodity prices. These factors were partially offset by higher commodity derivative settlement payments of approximately $10.9 million as well as higher expenses and production taxes.

Capital Resources and Liquidity

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

As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and developing additional hydrocarbon reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our revolving credit facility, if available, or obtain additional debt or equity financing. Our revolving credit facility and our senior notes limit our ability to issue additional debt, but permit us to issue limited amounts of unsecured senior or senior subordinated notes. Further, our existing revolving credit facility matures on April 1, 2019.

The amounts available for borrowing under our credit facility are subject to a borrowing base which is currently set at $950.0 million. As of July 31, 2014, we had $591.9 million available for borrowing under our revolving credit facility. Based on their commodity price expectations, our lenders redetermine the borrowing base semi-annually, with the next
redetermination scheduled on or around October 2014. Please see "— Financing Activities — Our Revolving Credit Facility."

Cash Flow from Operations

Our net cash provided by operating activities was $103.8 million and $123.3 million for the six-month periods ended June 30, 2014 and 2013, respectively. The 2014 period was impacted by higher operating expenses, partially offset by higher realized commodity prices and production.

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

Investing Activities

We invested cash capital of $503.2 million for the six-month period ended June 30, 2014. The total includes $445.3 million for the acquisition of oil and natural gas properties including the WPX Acquisition and 5 individually immaterial acquisitions as well as $57.9 million for development projects. Our cash capital expenditures were $132.6 million for the six-month period ended June 30, 2013. The total includes $93.3 million for the acquisition of oil and natural gas properties in 10 individually immaterial acquisitions, $38.2 million for development projects and $1.2 million of exploratory capital expenditures.

Our capital expenditure budget, which predominantly consists of drilling, recompletion and well stimulation projects, is currently $100.0 million for the year ending December 31, 2014, of which $57.9 million has been expended during the six months ended June 30, 2014. Our remaining borrowing capacity under our revolving credit facility is $591.9 million as of July 31, 2014. 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, non-operated capital requirements and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner. Based upon current oil and natural gas price expectations for the year ending December 31, 2014, 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 remaining planned capital expenditures. Future cash distributions will be at levels to be determined based on cash available for distribution, any remaining borrowing capacity for cash distributions under our credit facility, requirements to repay debt and any other factors the board of directors of our general partner may consider. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

We enter into oil and natural gas derivative transactions to reduce the impact of oil and natural gas price volatility on our operations. Currently, we use derivatives to offset price volatility on NYMEX oil and natural gas prices, which do not include the additional net discount to NYMEX WTI that we typically experience in the Permian Basin. For the six-month periods ended June 30, 2014 and 2013, we had favorable (unfavorable) cash settlements of $(9.6) million and $1.3 million, respectively, related to our commodity derivatives. At June 30, 2014, we had in place oil and natural gas derivatives covering significant portions of our estimated 2014 through 2018 oil and natural gas production.

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 institutions deemed by management as competent and competitive market makers. In addition, all of our current counterparties are current or former lenders under our revolving credit facility, which allows us to avoid margin calls. However, we cannot be assured that all of our counterparties will meet their obligations under our derivative contracts. Due to this uncertainty, we routinely monitor the creditworthiness of our counterparties.

The following tables summarize, for the periods indicated, our oil and natural gas derivatives currently in place as of July 31, 2014, covering the period from July 1, 2014 through December 31, 2018. We use derivatives, including swaps, enhanced swaps and three-way 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 mostly settled based upon the monthly average closing price of the front-month NYMEX WTI oil, the price on the last trading day of front-month NYMEX Henry Hub natural gas and published West Texas Waha, ANR-Oklahoma and Rocky Mountain CIG prices of natural gas.

Oil Swaps:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl		
July-December 2014	1,599,902	$93.58	$87.50	-	$101.50
2015	1,056,301	$93.93	$88.50	-	$100.20
2016	228,600	$87.94	$86.30	-	$99.85
2017	182,500	$84.75	$84.75		

Natural Gas Swaps:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu		
July-December 2014	12,625,262	$4.64	$3.61	-	$6.47
2015	16,219,300	$4.45	$4.15	-	$5.82
2016	1,419,200	$4.30	$4.12	-	$5.30

We have also entered into multiple NYMEX WTI crude oil derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk. If the market price is below the long put fixed price but above the short put fixed price, a three-way collar allows us to settle for the long put fixed price. A three-way collar also allows us to settle for WTI market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. The following table summarizes the three-way oil collar contracts currently in place as of July 31, 2014, covering the period from July 1, 2014 through June 30, 2017:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
July-December 2014	404,800	$71.59	$96.59	$110.71
2015	1,362,800	$65.08	$89.69	$111.84
2016	621,300	$63.37	$88.37	$106.40
2017	72,400	$60.00	$85.00	$104.20

We have also entered into multiple NYMEX WTI crude oil derivative enhanced swap contracts. The first type of enhanced swap contract combines buying a lower-priced put, selling a higher-priced put, and using the net proceeds from these positions to simultaneously obtain a swap at above market prices (“enhanced swap price”). If the market price is at or above the higher-priced short put, this contract allows us to settle at the enhanced swap price. If the market price is below the higher-priced short put but above the lower-priced long put, this contract allows us to settle for the market price plus the spread between the enhanced swap price and the higher-priced short put. If the market price is at or below the lower-priced long put, this contract allows us to settle for the lower-priced long put plus the spread between the enhanced swap price and the higher-priced short put. The following table summarizes these type of enhanced swap contracts currently in place as of July 31, 2014, covering the period from January 1, 2015 to

December 31, 2018:

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2015	365,000	$60.00	$80.00	$92.35
2016	183,000	$57.00	$82.00	$91.70
2017	182,500	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

We have also entered into other multiple NYMEX WTI crude oil derivative enhanced swap contracts. This second type of enhanced swap contract combines selling a put and using the net proceeds to simultaneously obtain a swap at above market prices, i.e. the enhanced swap price. If the market price is at or above the put, this contract allows us to settle at the enhanced swap price. If the market price is below the put, this contract allows us to settle for the market price plus the spread between the enhanced swap price and the put price. The following table summarizes these type of enhanced swap contracts currently in place as of July 31, 2014, covering the period from January 1, 2015 to December 31, 2015:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Swap Price per Bbl
2015	503,000	$74.12	$93.09

We have also entered into multiple NYMEX Henry Hub natural gas derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk. If the market price is below the long put fixed price but above the short put fixed price, a three-way collar allows us to settle for the long put fixed price. A three-way collar also allows us to settle for market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. The following table summarizes the three-way natural gas collar contracts currently in place as of July 31, 2014:

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
July-December 2014	240,000	$4.00	$4.65	$5.03
2015	8,040,000	$3.66	$4.21	$5.01
2016	5,580,000	$3.75	$4.25	$5.08
2017	5,040,000	$3.75	$4.25	$5.53

As of July 31, 2014, Legacy had the following Henry Hub NYMEX to Northwest Pipeline, West Texas WAHA, NGPL Midcon, San Juan Basin, and California SoCal NGI natural gas differential swaps paying a floating differential and receiving a fixed differential 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 2014	8,050,000	$(0.07)	$(0.12) -	$0.29
2015	19,200,000	$(0.12)	$(0.15) -	$0.19

Financing Activities

Our net cash provided by financing activities was $419.7 million for the six months ended June 30, 2014, compared to $9.7 million for the six months ended June 30, 2013. During the six months ended June 30, 2014, total net repayments under our revolving credit facility were $23.0 million while we raised $291.8 million in proceeds, net of original issue discount and fees paid to initial purchasers in our private offering of 6.625% senior notes due 2021, resulting in a total net borrowings of $274.0 million. Additionally, we received net proceeds from the issuance of our 8% Series A

Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") and 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units") in the amount of $224.2 million. The proceeds from our net borrowings and preferred equity issuances were used to fund the WPX Acquisition and 5 individually immaterial acquisitions. We had cash outflow during the six months ended June 30, 2014 in the amount of $69.2 million for distributions to unitholders which was funded from cash flow from operations. Cash provided by financing activities during the six months ended June 30, 2013 included $76.3 million in net borrowings under our revolving credit facility and $65.7 million for distributions to unitholders.

On April 17, 2014, Legacy issued 2,000,000 of its Series A Preferred Units in a public offering at a price of $25.00 per unit. On May 12, 2014 Legacy issued an additional 300,000 of our Series A Preferred Units pursuant to the underwriters' option to purchase additional Series A Preferred Units. Legacy received aggregate net proceeds of approximately $55.2 million, after deducting underwriting discounts and estimated offering expenses, from the offering of Series A Preferred Units during the three-months ended June 30, 2014.

On June 17, 2014, Legacy issued 7,000,000 of its Series B Preferred Units in a public offering at a price of $25.00 per unit. Legacy received aggregate net proceeds of approximately $169.1 million, after deducting underwriting discounts and estimated offering expenses, from the offering of Series B Preferred Units during the three-months ended June 30, 2014. On July 1, 2014 Legacy issued an additional 200,000 of its Series B Preferred Units pursuant to the underwriters' option to purchase additional Series B Preferred Units.

Distributions on the Series A Preferred Units and Series B Preferred Units (the "Preferred Units", collectively) are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of its general partner. Distributions on the Series A Preferred Units will be payable from, and including, the date of the original issuance to, but not including April 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions on the Series B Preferred Units will be payable from, and including, the date of the original issuance to, but not including June 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions accruing on and after April 15, 2024 for the Series A Preferred Units and June 15, 2024 for the Series B Preferred Units will accrue at an annual rate equal to the sum of (a) three-month LIBOR as calculated on each applicable date of determination and (b) 5.24% for Series A Preferred Units and 5.26% for Series B Preferred Units, based on the $25.00 liquidation preference per preferred unit.

At any time on or after April 15, 2019 or June 15, 2019, Legacy may redeem the Series A Preferred Units or Series B Preferred Units, respectively, in whole or in part, out of amounts legally available therefor, at a redemption price of $25.00 per Preferred Unit plus an amount equal to all accumulated and unpaid distributions thereon through and including the date of redemption, whether or not declared. Legacy may also redeem the Preferred Units in the event of a Change of Control.

The Series A Preferred Units and the Series B Preferred Units trade on NASDAQ under the symbols "LGCYP" and "LGCYO," respectively.

On June 4, 2014, Legacy issued 300,000 incentive distribution units representing limited partner interests in Legacy (the "Incentive Distribution Units") to WPX Energy Rocky Mountain, LLC ("WPX") as part of the WPX Acquisition. The Incentive Distribution Units issued to WPX include 100,000 Incentive Distribution Units that immediately vested along with the ability to vest in up to an additional 200,000 Incentive Distribution Units (the "Unvested IDUs") in connection with any future asset sales or transactions completed with us. Incentive Distribution Units that are not issued to WPX or other parties will remain in Legacy's treasury for the benefit of all limited partners until such time as Legacy may make future issuances of Incentive Distribution Units.

The Incentive Distribution Units represent a right to incremental cash distributions from Legacy after certain target levels of distributions are paid to unitholders, which targets are set above the current levels of Legacy's distributions to unitholders. The Unvested IDUs do not participate in cash distributions from Legacy until vested. The Unvested IDUs will automatically be forfeited on each of the first two anniversaries of the closing date of the WPX Acquisition in an amount per forfeiture equal to 66,666 Incentive Distribution Units and on the third anniversary of the closing date of the WPX Acquisition in an amount equal to 66,668 Incentive Distribution Units. Unvested IDUs that have not been forfeited will vest ratably at a rate of 10,000 Incentive Distribution Units per $35.5 million of additional cash consideration that is paid by Legacy to WPX or to a third party (along with the fair market value of any non-cash consideration) in connection with the consummation of any transaction by which Legacy acquires oil and natural gas properties (or rights therein or other assets related thereto) from WPX or jointly with WPX and such third party.

In addition, the vested and outstanding Incentive Distribution Units held by WPX may be converted by Legacy at any time when Legacy has made a distribution in respect of its units for each of the four full fiscal quarters prior to the delivery of its conversion notice, and the amount of the distribution in respect of the units for the full quarter immediately preceding delivery of its conversion notice was equal to at least $0.90 per unit; and the amount of all distributions during each quarter within the four-quarter period immediately preceding delivery of its conversion notice did not exceed the adjusted operating surplus for such quarter. Further, WPX also has the ability to convert any of its vested Incentive Distribution Units beginning three years after June 4, 2014. WPX may not transfer any of the Incentive Distribution Units it holds to any person that is not a controlled affiliate of WPX.

8% Senior Notes Due 2020

On December 4, 2012, we, together with our 100% owned subsidiary Legacy Reserves Finance Corporation, completed a private placement offering to eligible purchasers of an aggregate principal amount of $300 million of our 8% Senior Notes due 2020 (the "2020 Senior Notes"), which were subsequently registered through a public exchange offer that closed on January 8, 2014. The 2020 Senior Notes were issued at 97.848% of par. We received approximately $286.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by us.

We will have the option to redeem the 2020 Senior Notes, in whole or in part, at any time on or after December 1, 2016, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption, if redeemed during the twelve-month period beginning on December 1 of the years indicated below.

Year	Percentage	
2016	104.000	%
2017	102.000	%
2018 and thereafter	100.000	%

Prior to December 1, 2016, we may redeem all or any part of the 2020 Senior Notes at the “make-whole” redemption price. In addition, prior to December 1, 2015, we may at our option, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes at the redemption price of 108% with the net proceeds of a public or private equity offering. We may be required to offer to repurchase the 2020 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Our and Legacy Reserves Finance Corporation's obligations under the 2020 Senior Notes are guaranteed by our 100% owned subsidiaries Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the properties of the guarantor; (ii) in connection with any sale or other disposition of sufficient capital stock of the guarantor so that it no longer qualifies as our Restricted Subsidiary (as defined in the indenture); (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of the guarantor provided no default or event of default has occurred or is occurring; (vi) at such time the guarantor does not have outstanding guarantees of our, or any other guarantor's, other debt; or (vii) upon merging into, or transferring all of its properties to us or another guarantor and ceasing to exist. Refer to Note 11 - Subsidiary Guarantors in the Notes to the Condensed Consolidated Financial Statements for further details on our guarantors.

The indenture governing the 2020 Senior Notes limits our ability and the ability of certain of our subsidiaries to (i) sell assets; (ii) pay distributions on, repurchase or redeem equity interests or purchase or redeem our subordinated debt, provided that such subsidiaries may pay dividends to the holders of their equity interests (including us) and we may pay distributions to the holders of our equity interests subject to the absence of certain defaults, the satisfaction of a fixed charge coverage ratio test and so long as the amount of such distributions does not exceed our sum of available cash (as defined in our partnership agreement), net proceeds from the sales of certain securities and return of or reductions to capital from restricted investments; (iii) make certain investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from certain of our subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in certain transactions with affiliates; (ix) create unrestricted subsidiaries; and (x) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2020 Senior Notes are rated investment grade by each of Moody's Investors

Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and us and our subsidiaries will cease to be subject to such covenants. The indenture also includes customary events of default. We are in compliance with all financial and other covenants of the 2020 Senior Notes.

6.625% Senior Notes Due 2021

On May 28, 2013, we, together with our 100% owned subsidiary Legacy Reserves Finance Corporation, completed a private placement offering to eligible purchasers of an aggregate principal amount of $250 million of our 6.625% Senior Notes due 2021 (the "2021 Senior Notes"), which were subsequently registered through a public exchange offer that closed on March 18, 2014.

This issuance of our 2021 Senior Notes was at 98.405% of par. We received approximately $240.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by us.
On May 13, 2014, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of an additional $300.0 million of our 6.625% 2021 Senior Notes. This issuance of our 2021 Senior Notes was at 99.0% of par. Legacy received approximately $291.8 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by Legacy.
The terms of the 2021 Senior Notes, including details related to our guarantors, are substantially identical to the terms of the 2020 Senior Notes with the exception of the interest rate and redemption provisions noted below. We will have the option to redeem the 2021 Senior Notes, in whole or in part, at any time on or after June 1, 2017, at the specified redemption prices set forth below together with any accrued and unpaid interest to the date of redemption, if any, if redeemed during the twelve-month period beginning on June 1 of the years indicated below.

Year	Percentage	
2017	103.313	%
2018	101.656	%
2019 or thereafter	100.000	%

Prior to June 1, 2017, we may redeem all or any part of the 2021 Senior Notes at the “make-whole” redemption price as defined in the indenture. In addition, prior to June 1, 2016, we may at our option, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes at the redemption price of 106.625% with the net proceeds of a public or private equity offering. We may be required to offer to repurchase the 2021 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. We are in compliance with all financial and other covenants of the 2021 Senior Notes.
Our Revolving Credit Facility

Credit Facility

Previous Credit Agreement: On March 10, 2011, Legacy entered into a five-year $1 billion secured revolving credit facility (as amended, the "Previous Credit Agreement"). Borrowings under the Previous Credit Agreement were set to mature on March 10, 2016.

Current Credit Agreement: On April 1, 2014, Legacy entered into a five-year $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, Compass Bank, as syndication agent, UBS Securities LLC and U.S. Bank National Association, as co-documentation agents and the lenders party thereto (the “Current Credit Agreement”). Borrowings under the Current Credit Agreement mature on April 1, 2019. Legacy's obligations under the Current Credit Agreement are secured by mortgages on over 80% of the total value of its oil and natural gas properties as well as a pledge of all of its ownership interests in our operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base and contains a $2 million sub-limit for letters of credit. The borrowing base is currently set at $950.0 million. As of July 31, 2014, we have approximately $358.0 million drawn under the Current Credit Agreement, leaving approximately $591.9 million of current availability. The borrowing base is subject to semi-annual redeterminations on April 1 and October 1 of each year, commencing October 1, 2014. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. Legacy also has the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base then in effect. Any increase in the borrowing base requires the consent of all the lenders and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement. If the requisite 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 Current Credit Agreement so long as it does not increase the borrowing base then in effect.

Legacy may at any time issue additional senior notes or new debt whose proceeds are used to refinance such senior notes, subject to specified conditions in the Current Credit Agreement, which include that upon the issuance of such senior notes or new debt, the borrowing base shall be reduced by an amount equal to (i) (A) in the case of the senior notes, 25% of the stated principal amount of the senior notes and (B) in the case of the new debt, 25% of the portion of the new debt that exceeds the original principal amount of the senior notes or (ii) in the sole discretion of the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Current Credit Agreement prior to the issuance of the senior notes or new debt, a lesser amount. In addition, after giving pro forma effect to the issuance of any additional senior notes, we must continue to have a ratio of total debt to EBITDA of not more than 4.5 to 1.0 for four fiscal quarters preceding the issuance of the senior notes until June 15, 2015 and 4.0 to 1.0 thereafter. Outstanding borrowings in excess of the borrowing base must be prepaid, and, if mortgaged properties represent less than 80% of total value of oil and natural gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral.

Legacy may elect that borrowings be comprised entirely of ABR loans or Eurodollar loans. Interest on the loans is determined as follows:

- with respect to ABR loans, the alternate base rate equals the highest of (i) the prime rate, (ii) the Federal funds effective rate plus 0.50% and (iii) the one-month London interbank offered rate (LIBOR) plus 1.00%, in each case plus an applicable margin ranging from and including 0.50% and 1.50% per annum, determined by the percentage of the borrowing base then in effect that is drawn, or

- with respect to any Eurodollar loans, one-, two-, three- or six-month LIBOR, or, upon the consent of all of the lenders, twelve month LIBOR, in each case plus an applicable margin ranging from and including 1.50% and 2.50% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

Legacy pays a commitment fee ranging from and including 0.375% and 0.500% on the average daily amount of the unused amount of the commitments under the Current Credit Agreement.

The Current Credit Agreement contains various covenants that limit our ability to:

- incur indebtedness;

- enter into certain leases;

- grant certain liens;

- enter into certain swaps;

- make certain loans, acquisitions, capital expenditures and investments;

- make distributions other than from available cash;

- merge, consolidate or allow any material change in the character of our business; or

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

The Current Credit Agreement also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- total debt to EBITDA of not more than 4.5 to 1.0 through June 15, 2015 and 4.0 to 1.0 thereafter;

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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 FASB Accounting Standards Codification 815, which includes the current portion of oil, natural gas and interest rate derivatives; and

- specified minimum levels of natural gas hedges for each fiscal year.

EBITDA is defined as net income (loss) plus (i) interest expense, (ii) expense for income and income based taxes paid or accrued, (iii) depreciation, depletion, amortization, accretion and impairment, including without limitation, impairment of goodwill, and (iv) any non-cash items associated with (a) mark to market accounting related to derivatives or investments, (b) equity compensation and/or (c) any gains or losses attributable to writeups or writedowns of assets, including ceiling test writedowns; less, all non-cash items increasing net income, all on a consolidated basis.

If an event of default exists under the Current Credit Agreement, 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 $2.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;

- bankruptcy or insolvency events involving us or any of our subsidiaries;

- the loan documents cease to be in full force and effect;

- our failing to create a valid lien, except in limited circumstances;

- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of April 1, 2014 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) LRGPLLC’s ceasing to be our sole general partner;

- the entry of, and failure to pay, one or more adverse judgments in excess of $2.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and

- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year.

As of June 30, 2014, we were in compliance with all covenants of the Current Credit Agreement.

Legacy periodically enters into interest rate swap transactions to mitigate the volatility of interest rates. As of June 30, 2014, Legacy had interest rate swaps on notional amounts of $204 million with a weighted average fixed rate of 1.78%. These swaps mature between August 2014 and November 2015.

Off-Balance Sheet Arrangements

None.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires management to select and apply accounting policies that best provide the framework to report our results of operations and financial position. The selection and application of those policies requires management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of June 30, 2014, our critical accounting policies were consistent with those discussed in our Annual Report on Form 10-K for the period ended December 31, 2013.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves, the fair value of assets and liabilities acquired in business combinations, valuation of derivatives, future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations and accrued revenues. Actual results could differ from these estimates.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. ("ASU") 2014-08: Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (ASU 2014-08). ASU 2014-08 changes the criteria for reporting discontinued operations while enhancing disclosures in this area and is effective for annual and interim periods beginning after December 15, 2014. We are currently evaluating the provisions of ASU 2014-08 and assessing the impact, if any, it may have on our financial position and results of operations.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP.

The standard is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are currently evaluating the impact of our pending adoption of ASU 2014-09 on our consolidated financial statements and have not yet determined the method by which we will adopt the standard in 2017.

Item 3. Quantitative and Qualitative Disclosures 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. These derivative instruments are discussed in Item 1. Financial Statements – Notes to Consolidated Financial Statements – Note 7 Derivative Financial Instruments.

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

We periodically enter into and anticipate entering into derivative transactions with respect to a portion of our projected oil and natural gas production through various transactions that offset changes in the future prices received. These transactions may include swaps, enhanced swaps and three-way collars. These derivative transactions are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of June 30, 2014, the fair market value of our commodity derivative positions was a net liability of $20.0 million based on NYMEX futures prices from July 2014 to December 2018 for both oil and natural gas. As of December 31, 2013, the fair market value of our commodity derivative positions was a net asset of $17.7 million based on NYMEX futures prices from January 2014 to December 2017 for both oil and natural gas. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives from July 2014 through December 2018, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations— Investing Activities.”

Interest Rate Risks

At June 30, 2014, we had debt outstanding under its revolving credit facility of $325 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by us under our revolving credit facility for the six-month period ended June 30, 2014 was 2.8%. A 1% increase in LIBOR on our outstanding debt under our revolving credit facility as of June 30, 2014 would result in an estimated $1.21 million increase in annual interest expense assuming our current interest rate hedges remain in place and do not expire. We have entered into interest rate swaps with a weighted-average fixed rate of 1.78% to mitigate the volatility of interest rates on notional amounts of $204 million of floating rate debt, which will expire during 2014 and 2015.

Item 4. Controls and Procedures.

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

Our management, with the participation of our general partner’s chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of June 30, 2014. 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, 2014, 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 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, 2013 and our Quarterly Report on Form 10-Q for the period ended March 31, 2014, which could materially affect our business, financial condition or future results. The risks described in these reports 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.

Risks Related to the Preferred Units

Our Series A Preferred Units and Series B Preferred Units rank senior in right of payment to our units, and we are unable to make any distribution to our unitholders unless full cumulative distributions are made on our Series A Preferred Units and Series B Preferred Units.

We have issued 2,300,000 of our Series A Preferred Units. We have also issued 7,200,000 of our Series B Preferred Units. The Preferred Units represent perpetual equity interests in us and rank senior in right of payment to our units. Distributions on the Preferred Units are cumulative from the date of original issue and are payable monthly on the 15th day of each month. No distribution may be declared or paid or set apart for payment on the units, or any other junior securities, unless full cumulative distributions have been or contemporaneously are being paid or provided for on all outstanding Preferred Units and any parity securities through the most recent respective distribution payment dates.

The Preferred Units are subordinated to our existing and future debt obligations, and could be diluted by the issuance of additional partnership securities, including additional Preferred Units, and by other transactions.

The Preferred Units are subordinated to all of our existing and future indebtedness (including indebtedness outstanding under our Current Credit Agreement, our 8% Senior Notes due 2020 and our 6.625% Senior Notes due 2021). We may incur additional debt under our Current Credit Agreement or future credit facilities or by issuing additional senior or subordinated debt securities. The payment of principal and interest on our debt reduces cash available for distribution to limited partners, including the holders of Preferred Units.

The issuance of additional partnership securities pari passu with or senior to the Preferred Units would dilute the interests of the holders of the Preferred Units, and any issuance of senior securities or parity securities or additional indebtedness could affect our ability to pay distributions on, redeem or pay the liquidation preference on the Preferred Units. Only the Change of Control provision relating to the Preferred Units protects the holders of the Preferred Units in the event of a highly leveraged or other transaction, including a merger or the sale, lease or conveyance of all or substantially all our assets or business, which might adversely affect the holders of the Preferred Units.

Treatment of distributions on our Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our Preferred Units than the holders of our units.

The tax treatment of distributions on our Preferred Units is uncertain. We will treat the holders of Preferred Units as partners for tax purposes and will treat distributions on the Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Preferred Units as ordinary income. Although a holder of Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions monthly.

Otherwise, the holders of Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction. Nor will we allocate any share of our nonrecourse liabilities to the holders of Preferred Units. If the Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of Preferred Units.

A holder of Preferred Units will be required to recognize gain or loss on a sale of units equal to the difference between such holder's amount realized and tax basis in the Preferred Units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Preferred Units. Subject, in certain circumstances, to rules requiring a blended basis among multiple partnership interests, the tax basis of an Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder of the Preferred Unit to acquire such Preferred Unit. Gain or loss recognized by a holder of the Preferred Unit on the sale or exchange of an Preferred Unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of Preferred Units will not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in our Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-U.S. persons raises issues unique to them. Distributions to non-U.S. holders of our Preferred Units will be treated as "effectively connected income" (which will subject holders to U.S. net income taxation and possibly the branch profits tax) and will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax exempt investors is not certain. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor with respect to the consequences of owning our Preferred Units.

Risks Related to Our Limited Partnership Structure

Our general partner may elect to cause us to issue units in connection with a resetting of incentive distribution levels without the approval of our unitholders. Our Incentive Distribution Units may be converted to units in certain circumstances. Any such election or conversion may result in lower distributions to our unitholders in certain situations.

Our general partner has the right, at any time when the partnership has paid distributions of at least $0.7375 for each of the prior four consecutive fiscal quarters and the amount of all distributions during each quarter within such four-quarter period did not exceed the adjusted operating surplus for each such quarter, to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per unit, taking into account the existing levels of incentive distribution payments being made to the holders of Incentive Distribution Units. It is possible that our general partner exercises this reset right at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the Incentive Distribution Units expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the Incentive Distribution Units may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the Incentive Distribution Units and may therefore desire to be issued our units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for them to own in lieu of the right to receive incentive distribution payments based on increased target distribution levels that are less certain to be achieved. As a result, a reset election may cause our unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new units to the holders of the Incentive Distribution Units in connection with resetting the target distribution levels.

Further, our general partner and Incentive Distribution Unitholders may cause vested and outstanding Incentive Distribution Units to convert to units in certain other circumstances. Any such conversion may cause our unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new units to the holders of the Incentive Distribution Units in connection with any such conversion.

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

On June 4, 2014, we issued 300,000 Incentive Distribution Units, which are a limited partner interest in the Partnership. These were issued in connection with the contribution of certain oil and gas interests to the Partnership. The Incentive Distribution Units are convertible into our units under certain circumstances based on distribution amounts to our unitholders at the time of conversion as more fully described in our Fourth Amended and Restated Agreement of Limited Partnership of the Partnership. The issuance of these Incentive Distribution Units were exempt from registration under Regulation D of the Securities Act because the issuance was made to an “accredited investor” as such term is defined in Regulation D of the Securities Act.

Purchases of Equity Securities

Period	(a) Total number of units purchased	(b) Price paid per unit	(c) Total number of units purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value of units) that may yet be purchased under the plans or programs
May 19, 2014	10,429(1)	$28.07	—	—

(1) These units were purchased by the Partnership in satisfaction of certain employee tax withholding obligations at a price of $28.07 per unit, the closing price of Legacy's units on the NASDAQ Global Market on such date.

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	Fourth 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 June 17, 2014, Exhibit 3.1)
3.4	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.5	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
3.6	First Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Quarterly Report on Form 10-Q (File No. 001-33249) filed May 4, 2012, Exhibit 3.6)
3.7	Second Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's Quarterly Report on Form 10-Q (File No. 001-33249) filed May 4, 2012, Exhibit 3.7)
4.1	Indenture, dated as of May 28, 2013, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (including form of the 6.625% Senior Notes due 2021) (Incorporated by reference to Legacy's Current Report on Form 8-K (File No. 001-33249) filed May 31, 2013, Exhibit 4.1)
4.2	Registration Rights Agreement, dated as of May 28, 2013, by and among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, LLC, UBS Securities LLC, Barclays Capital Inc., Citigroup Global Markets Inc. and J.P. Morgan Securities LLC as representatives of the Initial Purchasers named therein. (Incorporated by reference to Legacy's Current Report on Form 8-K (File No. 001-33249) filed May 31, 2013, Exhibit 4.2)
4.3	Registration Rights Agreement, dated as of May 13, 2014, by and among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, LLC, UBS Securities LLC, Citigroup Global Markets Inc., Barclays Capital Inc. and J.P. Morgan Securities LLC as representatives of the Initial Purchasers named therein (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed May 13, 2014, Exhibit 4.2)
10.1	Third Amended and Restated Credit Agreement, dated as of April 1, 2014, among Legacy Reserves LP, Wells Fargo Bank, National Association, as administrative agent, Compass Bank, as syndication agent, UBS Securities LLC and U.S. Bank National Association, as co-documentation agents, and certain other financial institutions party thereto as Lenders (Incorporated by reference to Legacy's Current Report on Form 8-K (File No. 001-33249) filed April 2, 2014, Exhibit 10.1).
10.2	Purchase and Sale Agreement, dated May 2, 2014, by and between WPX Energy Rocky Mountain, LLC, Legacy Reserves Operating LP, Legacy Reserves GP, LLC and Legacy Reserves LP (Incorporated by reference to Legacy’s Current Report on Form 8-K (File No. 001-33249) filed May 6, 2014, Exhibit 2.1).

10.3*	First Amendment to Third Amended and Restated Credit Agreement, dated April 17, 2014, by and between Legacy Reserves LP, Wells Fargo Bank, National Association, as administrative agent and certain other financial institutions party thereto as lenders.
10.4	Second Amendment to Third Amended and Restated Credit Agreement, dated May 22, 2014, by and between Legacy Reserves LP, Wells Fargo Bank, National Association, as administrative agent and certain other financial institutions party thereto as lenders (Incorporated by reference to Legacy's Current Report on Form 8-K (File No. 001-33249) filed May 28, 2014, Exhibit 10.1).
10.5	IDR Holders Agreement, dated June 4, 2014, by and between Legacy Reserves LP and WPX Rocky Mountain, LLC (Incorporated by reference to Legacy's Current Report on Form 8-K (File No. 001-33249) filed June 4, 2014, 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)
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.DEF**	XBRL Taxonomy Extenstion Definition Linkbase Document
101.PRE**	XBRL Taxonomy Extenstion Presentation Linkbase Document
101.CAL**	XBRL Taxonomy Extenstion Calculation Linkbase Document
101.LAB**	XBRL Taxonomy Extenstion Label Linkbase Document

* Filed herewith

** Filed electronically herewith.

SIGNATURES

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

LEGACY RESERVES LP

By: Legacy Reserves GP, LLC, its General Partner

August 1, 2014

By: /s/ James Daniel Westcott
James Daniel Westcott
Executive Vice President and Chief Financial Officer
(On behalf of the Registrant and as Principal Financial Officer)