LEGACY RESERVES LP
Form 10-Q
August 03, 2016

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, 2016

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

72,411,046 units representing limited partner interests in the registrant were outstanding as of August 1, 2016.

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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, 2016	December 31, 2015
	(In thousands)	
Current assets:		
Cash	$ 1,140	$ 2,006
Accounts receivable, net:		
Oil and natural gas	35,578	33,944
Joint interest owners	13,752	25,378
Other	2	86
Fair value of derivatives (Notes 6 and 7)	23,188	63,711
Prepaid expenses and other current assets (Note 1)	7,724	4,334
Total current assets	81,384	129,459
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	3,307,925	3,485,634
Unproved properties	13,653	13,424
Accumulated depletion, depreciation, amortization and impairment	(2,048,928)	(2,090,102)
	1,272,650	1,408,956
Other property and equipment, net of accumulated depreciation and amortization of $9,754 and $8,915, respectively	4,048	4,575
Operating rights, net of amortization of $5,161 and $4,953, respectively	1,856	2,064
Fair value of derivatives (Notes 6 and 7)	30,254	56,373
Other assets	10,109	11,047
Investments in equity method investees	633	646
Total assets	$ 1,400,934	$ 1,613,120

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2016	December 31, 2015
	(In thousands)	
Current liabilities:		
Accounts payable	$3,722	$13,581
Accrued oil and natural gas liabilities (Note 1)	55,086	50,573
Fair value of derivatives (Notes 6 and 7)	3,047	2,019
Asset retirement obligation (Note 8)	3,496	3,496
Other (Note 10)	7,594	11,424
Total current liabilities	72,945	81,093
Long-term debt (Note 2)	1,173,009	1,427,614
Asset retirement obligation (Note 8)	266,427	282,909
Fair value of derivatives (Notes 6 and 7)	3,469	—
Other long-term liabilities	1,195	1,181
Total liabilities	1,517,045	1,792,797
Commitments and contingencies (Note 5)		
Partners' deficit (Note 9):		
Series A Preferred equity - 2,300,000 units issued and outstanding at June 30, 2016 and December 31, 2015	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at June 30, 2016 and December 31, 2015	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at June 30, 2016 and December 31, 2015	30,814	30,814
Limited partners' deficit - 72,055,697 and 68,949,961 units issued and outstanding at June 30, 2016 and December 31, 2015, respectively	(376,260)	(439,811)
General partner's deficit (approximately 0.03%)	(118)	(133)
Total partners' deficit	(116,111)	(179,677)
Total liabilities and partners' deficit	$1,400,934	$1,613,120

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,	
	2016	2015	2016	2015
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$41,272	$59,113	$71,592	$109,409
Natural gas liquids (NGL) sales	3,922	5,729	6,375	9,921
Natural gas sales	28,173	22,959	61,259	50,010
Total revenues	73,367	87,801	139,226	169,340
Expenses:				
Oil and natural gas production	44,561	45,220	94,584	94,440
Production and other taxes	3,390	3,986	5,963	8,204
General and administrative	10,993	10,390	20,427	19,259
Depletion, depreciation, amortization and accretion	37,668	36,197	74,627	77,265
Impairment of long-lived assets	—	—	15,447	209,402
(Gain) loss on disposal of assets	(9,141)	(934)	(40,842)	1,007
Total expenses	87,471	94,859	170,206	409,577
Operating loss	(14,104)	(7,058)	(30,980)	(240,237)
Other income (expense):				
Interest income	16	176	54	382
Interest expense (Notes 2, 6 and 7)	(20,302)	(17,760)	(45,478)	(35,552)
Gain on extinguishment of debt (Note 2)	19,998	—	150,802	—
Equity in income (loss) of equity method investees	(9)	24	(14)	103
Net gains (losses) on commodity derivatives (Notes 6 and 7)	(37,675)	(13,497)	(20,637)	6,983
Other	(98)	97	(192)	702
Income (loss) before income taxes	(52,174)	(38,018)	53,555	(267,619)
Income tax (expense) benefit	(87)	(456)	(487)	291
Net income (loss)	$(52,261)	$(38,474)	$53,068	$(267,328)
Distributions to preferred unitholders	(4,750)	(4,750)	(8,708)	(9,500)
Net income (loss) attributable to unitholders	$(57,011)	$(43,224)	$44,360	$(276,828)
Income (loss) per unit - basic & diluted (Note 9)	$(0.81)	$(0.63)	$0.64	$(4.02)
Weighted average number of units used in computing net income (loss) per unit -				
Basic and diluted	70,071	68,897	69,518	68,909

See accompanying notes to condensed consolidated financial statements.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' DEFICIT
FOR THE SIX MONTHS ENDED JUNE 30, 2016
(UNAUDITED)

	Series A Preferred Equity		Series B Preferred Equity		Incentive Distribution Equity		Unitholders' Equity (Deficit)			
	Units	Amount	Units	Amount	Units	Amount	Limited Partner Units	Limited Partner Amount	General Partner Amount	Total Partners' Equity (Deficit)
	(In thousands)									
Balance, December 31, 2015	2,300	$55,192	7,200	$174,261	100	$30,814	68,950	$(439,811)	$(133)	$(179,677)
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	237	614	—	614
Unit-based compensation	—	—	—	—	—	—	—	3,275	—	3,275
Vesting of restricted and phantom units	—	—	—	—	—	—	150	—	—	—
Units issued in exchange for Senior Notes							2,719	6,609		6,609
Net income	—	—	—	—	—	—	—	53,053	15	53,068
Balance, June 30, 2016	2,300	$55,192	7,200	$174,261	100	$30,814	72,056	$(376,260)	$(118)	$(116,111)

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2016	2015
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$53,068	$(267,328)
Adjustments to reconcile net income (loss) to net cash (used in) provided by operating activities:		
Depletion, depreciation, amortization and accretion	74,627	77,265
Amortization of debt discount and issuance costs	6,975	2,680
Gain on extinguishment of debt	(150,802)	—
Impairment of long-lived assets	15,447	209,402
(Gain) loss on derivatives	26,269	(8,078)
Equity in (income) loss of equity method investees	14	(103)
Distribution from equity method investee	—	191
Unit-based compensation	4,003	3,174
(Gain) loss on disposal of assets	(40,842)	1,007
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, oil and natural gas	(1,634)	8,155
Decrease in accounts receivable, joint interest owners	11,626	3,811
(Increase) decrease in accounts receivable, other	84	(17)
Increase in other assets	(2,452)	(241)
Decrease in accounts payable	(9,859)	(1,368)
Increase (decrease) in accrued oil and natural gas liabilities	4,513	(23,948)
Decrease in other liabilities	(5,663)	(4,396)
Total adjustments	(67,694)	267,534
Net cash provided by (used in) operating activities	(14,626)	206
Cash flows from investing activities:		
Investment in oil and natural gas properties	(14,103)	(23,704)
Proceeds from sale of assets	87,475	740
Investment in other equipment	(312)	(181)
Net cash settlements received on commodity derivatives	44,871	77,526
Net cash provided by investing activities	117,931	54,381
Cash flows from financing activities:		
Proceeds from long-term debt	81,000	155,000
Payments of long-term debt	(181,402)	(129,000)
Payments of debt issuance costs	(3,769)	(1,475)
Proceeds from the issuance of units, net	—	(71)
Distributions to unitholders	—	(76,105)
Net cash used in financing activities	(104,171)	(51,651)
Net increase (decrease) in cash and cash equivalents	(866)	2,936
Cash, beginning of period	2,006	725
Cash, end of period	$1,140	$3,661
Non-cash investing and financing activities:		
Asset retirement obligations associated with properties sold	$(21,664)	$(4,553)
Asset retirement obligations associated with property acquisitions	$—	$18,756

Units acquired in exchange for equity method investee interest	$—	$1,349
Units issued in exchange for outstanding Senior Notes	$(6,607)	$—

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, 2016 and for the three and six months ended June 30, 2016 and 2015 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, 2015.

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), East Texas, Rocky Mountain and Mid-Continent 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, 2016 and December 31, 2015:

	June 30, 2016	December 31, 2015
	(In thousands)	
Revenue payable to joint interest owners	$23,493	$ 15,253
Accrued lease operating expense	15,070	19,007
Accrued capital expenditures	2,180	2,881
Accrued ad valorem tax	9,137	8,723
Other	5,206	4,709
	$55,086	$ 50,573

(c) Restricted Cash

Restricted cash on our Balance Sheet as of June 30, 2016 is recorded as $2.9 million in the "Prepaid expenses and other current assets" line. The restricted cash amounts represent various deposits to secure the performance of contracts, surety bonds and other obligations incurred in the ordinary course of business. There was no restricted cash recorded at December 31, 2015.

(d) Recent Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2016-02, "Leases" ("ASU 2016-02"). ASU 2016-02 establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are currently evaluating the impact of our pending adoption of ASU 2016-02 on our consolidated financial statements.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, "Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern" (“ASU 2014-15”). ASU 2014-15 requires management to assess an entity’s ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. The standard is effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016, with early adoption permitted. We are currently evaluating the provisions of ASU 2014-15 and do not anticipate any impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 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. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers" ("ASU 2015-14"), which approved a one-year delay of the standard's effective date. In accordance with ASU 2015-14, the standard is now effective for annual periods beginning after December 15, 2017, 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 do not anticipate the standard will have a material impact on our consolidated financial statements.

(e) Prior Year Financial Statement Presentation

Certain prior year balances have been reclassified to conform to the current year presentation of balances as stated in this quarterly report on Form 10-Q. Please read Note 2—Long-Term Debt for further discussion regarding this reclassification.

(2) Long-Term Debt

Long-term debt consists of the following as of June 30, 2016 and December 31, 2015:

	June 30, 2016	December 31, 2015
	(In thousands)	
Credit Facility due 2019	$533,000	$608,000
8% Senior Notes due 2020	232,989	300,000
6.625% Senior Notes due 2021	432,656	550,000
	1,198,645	1,458,000
Unamortized discount on Senior Notes	(12,916)	(17,604)
Unamortized debt issuance costs (a)	(12,720)	(12,782)
Total Long-Term Debt	$1,173,009	$1,427,614

(a) In order to comply with Accounting Standards Update No. 2015-03, unamortized debt issuance costs are now recorded as a direct deduction from the carrying amount of debt. As such, debt issuance costs have been reclassified from other assets to long-term debt on a retrospective basis. This reclassification had no impact on historical income from continuing operations or retained earnings.

Credit Facility

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 90% 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 $630 million. The borrowing base is subject to semi-annual redeterminations on or about April 1 and October 1 of each year with the next redetermination scheduled for October 2016. 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.

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

- first lien debt to EBITDA for the four fiscal quarters ending on last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available to be less than: (i) 3.50 to 1.00, at any time during the period from and including February 19, 2016 through December 31, 2016, (ii) 3.25 to 1.00, at any time during the fiscal quarter ending March 31, 2017, (iii) 3.00 to 1.00, at any time during the fiscal quarter ending June 30, 2017 and (iv) 2.50 to 1.00, at any time on or after July 1, 2017;
- as of the last day of the most recent quarter, total EBITDA over the last four quarters to total Interest Expense over the last four quarters to be greater than (i) 2.50 to 1.00 for the fiscal quarters ending December 31, 2015 and March 31, 2016, (ii) 2.00 to 1.00 for the fiscal quarters ending June 30, 2016, September 30, 2016, December 31, 2016, March 31, 2017 and June 30, 2017 and (iii) 2.50 to 1.00 for each fiscal quarter ending on or after September 30, 2017; and
- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC 815, which includes the current portion of oil, natural gas and interest rate derivatives.

As of June 30, 2016, Legacy was in compliance with all financial and other covenants of the Current Credit Agreement. Depending on oil and natural gas prices in 2016, Legacy could breach certain financial covenants under its revolving credit facility, which would constitute a default under its revolving credit facility. Such default, if not remedied, would require a waiver from Legacy's lenders in order for it to avoid an event of default and subsequent acceleration of all amounts outstanding under its revolving credit facility and potential foreclosure on its oil and natural gas properties. If the lenders under Legacy's revolving credit facility were to accelerate the indebtedness under its revolving credit facility as a result of a default, such acceleration could cause a cross-default of all of its other outstanding indebtedness, including its 8% Senior Notes due 2020 (the "2020 Senior Notes") and its 6.625% Senior Notes due 2021 (the "2021 Senior Notes" and, together with the 2020 Senior Notes, the “Senior Notes”), and permit the holders of such indebtedness to accelerate the maturities of such indebtedness. While no assurances can be made that, in the event of a covenant breach, such a waiver will be granted, Legacy believes the long-term global outlook for commodity prices and its efforts to date, which include the suspension of distributions to its unitholders and holders of both its 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") and its 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units" and, together with the Series A Preferred Units, the “Preferred Units”), as well as asset sales completed as of the date of this filing, will be viewed positively by its lenders.

As of June 30, 2016, Legacy had approximately $533.0 million drawn under the Current Credit Agreement at a weighted-average interest rate of 3.22%, leaving approximately $95.6 million of availability under the Current Credit Agreement. For the six-month period ended June 30, 2016, Legacy paid in cash $9.3 million of interest expense on the Current 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 its 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. 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., Legacy Reserves Energy Services LLC, Dew Gathering LLC and Pinnacle Gas Treating LLC, 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. However, if the lenders under Legacy's Current Credit Agreement were to accelerate the indebtedness under Legacy's Current Credit Agreement as a result of a default, such acceleration could cause a cross-default of all of the 2020 Senior Notes and permit the holders of such notes to accelerate the maturities of such indebtedness.

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

During the six months ended June 30, 2016, Legacy repurchased a face amount of $52.0 million of its 2020 Senior Notes on the open market. Legacy treated these repurchases as an extinguishment of debt. Accordingly, Legacy recognized a gain for the difference between (1) the face amount of the 2020 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price.

On June 1, 2016, Legacy exchanged 2,719,124 units representing limited partner interests in the Partnership for $15.0 million of face amount of its outstanding 2020 Senior Notes. Legacy treated this exchange as an extinguishment of debt. Accordingly, Legacy recognized a gain for the difference between (1) the face amount of the 2020 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the fair value of the units issued in the exchange based on the closing price on June 1, 2016.

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 its 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, which were subsequently registered through a public exchange offer that closed on February 10, 2015. 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. However, if the lenders under Legacy's Current Credit Agreement were to accelerate the indebtedness under Legacy's Current Credit Agreement as a result of a default, such acceleration could cause a cross-default of all of the 2021 Senior Notes and permit the holders of such notes to accelerate the maturities of such indebtedness.

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

During the six months ended June 30, 2016, Legacy repurchased a face amount of $117.3 million of its 2021 Senior Notes on the open market. Legacy treated these repurchases as an extinguishment of debt. Accordingly, Legacy recognized a gain for the difference between (1) the face amount of the 2021 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price.

(3) Acquisitions

On July 31, 2015, Legacy purchased (1) 100% of the issued and outstanding limited liability company membership interests in Dew Gathering LLC, which owns directly and indirectly natural gas gathering and processing assets in Anderson, Freestone, Houston, Leon, Limestone and Robertson Counties, Texas (the "WGR Acquisition") from WGR Operating LP ("WGR") for a net purchase price of $96.7 million, and (2) various oil and natural gas properties and associated exploration and production assets (the "Anadarko E&P Acquisition," together with the WGR Acquisition, the "Anadarko Acquisitions") from Anadarko E&P Onshore LLC ("Anadarko") for a net purchase price of $337.2 million. The Anadarko Acquisitions were accounted for as a business combination.

The allocation of the Anadarko Acquisitions 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	$461,306
Future abandonment costs	(27,351)
Fair value of net assets acquired	$433,955

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the Anadarko Acquisitions had occurred on January 1, 2014. 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, 2015	Six Months Ended June 30, 2015
Revenues	$119,416	$233,877
Net loss attributable to unitholders	$(29,151)	$(247,638)
Loss per unit — basic and diluted	$(0.42)	$(3.59)
Units used in computing loss per unit:		
Basic and diluted	68,897	68,909

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

	Three Months Ended June 30, 2016	Six Months Ended June 30, 2016
	(In thousands)	
Anadarko Acquisitions		
Revenues	$10,387	$21,865
Excess of revenues over direct operating expenses	$4,362	$8,518

(4) Related Party Transactions

Blue Quail Energy Services, LLC ("Blue Quail"), a company specializing in water transfer services, is an affiliate of Moriah Energy Services LLC, an entity which Cary D. Brown and Dale A. Brown, both directors of Legacy, are principals. Legacy has contracted with Blue Quail to provide water transfer services and paid $82,587 and $93,193 in the six month periods ended June 30, 2016 and June 30, 2015, respectively, to Blue Quail for such services. Blue Quail charged Legacy prices consistent with that of other vendors for services rendered.

(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 party to a contractual agreement, extending through 2022, to purchase CO_2 volumes from a third party. The contract requires Legacy to purchase minimum annual volumes, the pricing of which is calculated as a percentage of NYMEX-WTI oil prices, with a floor of $57.14. Based upon the minimum required volumes and the NYMEX-WTI strip prices as of June 30, 2016, we estimate the value of our total future obligation through the term of the agreement to be approximately $50.5 million.

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

Fair value is defined as 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. Fair value measurements are 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. Level 3 instruments currently are limited to Midland-Cushing crude oil differential swaps. Although Legacy utilizes third party broker quotes to assess the reasonableness of its prices and valuation techniques, Legacy does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

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, 2016:

	Fair Value Measurements at June 30, 2016 Using			
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of June 30, 2016

	(In thousands)					
LTIP liability (a)	$—	$ (113	)	$ —		$ (113)
Oil and natural gas derivatives	—	54,210		(1,290	)	52,920
Interest rate swaps	—	(5,994	)	—		(5,994)
Total	$—	$ 48,103		$ (1,290	)	$ 46,813

(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 London interbank offered rates ("LIBOR") and interest rate swaps. Due to the lack of an active market for periods beyond one-month from the balance sheet date for its oil price differential swaps, Legacy has reviewed historical differential prices and known economic influences to estimate a reasonable forward curve of future pricing scenarios based upon these factors. 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 most of our 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		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(In thousands)			
Beginning balance	$(2,828)	$(2,485)	$(4,493)	$555
Total gains (losses)	888	(3,275)	899	(6,632)
Settlements, net	650	949	2,304	1,266
Ending balance	$(1,290)	$(4,811)	$(1,290)	$(4,811)
Gains (losses) included in earnings relating to derivatives still held as of June 30, 2016 and 2015	$581	$(3,492)	$978	$(4,811)

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 Legacy's consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on Legacy's 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.

Nonrecurring fair value measurements of proved oil and natural gas properties during the six-month period ended June 30, 2016 consist of:

	Fair Value Measurements During the Six Months Ended June 30, 2016 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)	$ —	$ —	$ 19,783

(a) Legacy periodically reviews oil and natural gas properties for impairment when facts and circumstances indicate that their carrying value may not be recoverable. During the six-month period ended June 30, 2016, Legacy incurred impairment charges of $15.4 million as oil and natural gas properties with a net cost basis of $35.2 million were written down to their fair value of $19.8 million. In order to determine whether the carrying value of an asset is 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. 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.

The carrying amount of the revolving long-term debt of $533 million as of June 30, 2016 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, 2016, the fair values of the 2020 Senior Notes and the 2021 Senior Notes were $111.6 million and $182.8 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.

(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 and required no upfront or deferred cash 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, all of whom are 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, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
Beginning fair value of commodity derivatives	$112,688	$133,242	$118,427	$153,099
Total gain (loss) - oil derivatives	(5,411)	(12,649)	(2,892)	945
Total gain (loss) - natural gas derivatives	(32,264)	(848)	(17,745)	6,038
Crude oil derivative cash settlements received	(9,760)	(27,364)	(22,345)	(59,564)
Natural gas derivative cash settlements received	(12,333)	(9,825)	(22,525)	(17,962)
Ending fair value of commodity derivatives	$52,920	$82,556	$52,920	$82,556

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, 2016		
	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	$85,562	$ (32,120)	$ 53,442
Total derivative assets	$85,562	$ (32,120)	$ 53,442
Offsetting Derivative Liabilities:			
Commodity derivatives	$(32,642)	$ 32,120	$ (522)
Interest rate derivatives	(5,994)	—	(5,994)
Total derivative liabilities	$(38,636)	$ 32,120	$ (6,516)

	December 31, 2015		
	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	$177,082	$ (58,655)	$ 118,427
Interest rate derivatives	1,982	(325)	1,657
Total derivative assets	$179,064	$ (58,980)	$ 120,084
Offsetting Derivative Liabilities:			
Commodity derivatives	$(58,655)	$ 58,655	$ —
Interest rate derivatives	(2,344)	325	(2,019)
Total derivative liabilities	$(60,999)	$ 58,980	$ (2,019)

As of June 30, 2016, 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:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2016	1,002,800	$55.24	$50.15 - $91.00
2017	182,500	$84.75	$84.75

As of June 30, 2016, Legacy had the following Midland-to-Cushing crude oil differential swaps paying a floating differential and receiving a fixed differential for a portion of its future oil production as indicated below:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2016	1,472,000	$(1.60)	$(1.50) - $(1.75)
2017	2,190,000	$(0.30)	$(0.05) - $(0.75)

As of June 30, 2016, Legacy had the following NYMEX WTI crude oil derivative three-way collar contracts that combine a long and short put with a short call as indicated below:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
July-December 2016	230,000	$60.00	$85.00	$102.46
2017	72,400	$60.00	$85.00	$104.20

As of June 30, 2016, Legacy had the following NYMEX WTI crude oil enhanced swap contracts that combine a short put and long put with a fixed-price swap as indicated below:

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
July-December 2016	92,000	$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, 2016, Legacy had the following NYMEX Henry Hub and West Texas Waha natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
July-December 2016	24,973,600	$3.01	$2.42-$5.30
2017	27,600,000	$3.36	$3.29-$3.39
2018	27,600,000	$3.36	$3.29-$3.39
2019	25,800,000	$3.36	$3.29-$3.39

As of June 30, 2016, 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:

Time Period	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
July-December 2016	2,790,000	$3.75	$4.25	$5.08
2017	5,040,000	$3.75	$4.25	$5.53

As of June 30, 2016, Legacy had the following Henry Hub NYMEX to Northwest Pipeline, California SoCal NGI and San Juan Basin 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:

	July-December 2016		2017	
	Volumes (MMBtu)	Average Price per MMBtu	Volumes (MMBtu)	Average Price per MMBtu
NWPL	7,529,832	$(0.19)	7,300,000	$(0.16)
SoCal	—	$—	2,500,250	$0.11
San Juan	1,256,720	$(0.16)	2,500,250	$(0.10)

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 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		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(In thousands)			
Beginning fair value of interest rate swaps	$(4,695)	$(1,540)	$(362)	$(2,080)
Total loss on interest rate swaps	(1,977)	(143)	(7,049)	(291)
Cash settlements paid	678	698	1,417	1,386
Ending fair value of interest rate swaps	$(5,994)	$(985)	$(5,994)	$(985)

The table below summarizes the interest rate swap position as of June 30, 2016:

Notional Amount	Weighted Average Fixed Rate	Effective Date	Maturity Date	Estimated Fair Value at June 30, 2016
(Dollars in thousands)				
$115,000	0.850 %	9/1/2015	9/1/2017	$(1,588)
$235,000	1.363 %	9/1/2015	9/1/2019	(4,406)
Total fair value of interest rate derivatives				$(5,994)

(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, 2016 and year ended December 31, 2015:

	June 30, 2016	December 31, 2015
	(In thousands)	
Asset retirement obligation - beginning of period	$286,405	$ 226,525
Liabilities incurred with properties acquired	—	60,526
Liabilities incurred with properties drilled	—	92
Liabilities settled during the period	(1,172)	(2,615)
Liabilities associated with properties sold	(21,664)	(9,386)
Current period accretion	6,354	11,263
Asset retirement obligation - end of period	$269,923	$ 286,405

(9) Partners' Equity

Preferred Units

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 Series A Preferred Units pursuant to the underwriters' option to purchase additional Series A Preferred Units.

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. On July 1, 2014, the underwriters exercised their over-allotment option to purchase an additional 200,000 Series B Preferred Units.

Distributions on 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.

On January 21, 2016, Legacy announced that its general partner suspended monthly cash distributions for both its Series A Preferred Units and its Series B Preferred Units. As of June 30, 2016, $0.92 of distributions per unit were in arrears, representing a total cumulative arrearage of approximately $8.7 million.

Incentive Distribution Units

On June 4, 2014, Legacy issued 300,000 Incentive Distribution Units representing limited partner interests in the Partnership (the "Incentive Distribution Units") to WPX Energy Rocky Mountain, LLC (“WPX”) as part of Legacy’s purchase of a non-operated interest in oil and natural gas properties located in the Piceance Basin in Garfield County, Colorado from WPX on June 4, 2014 (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. Effective January 1, 2016, WPX assigned its vested and unvested IDUs to WPX Energy Holdings, LLC ("WPX Holdings"), a controlled affiliate of WPX Energy, Inc.

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. 66,666 Unvested IDUs were forfeited on each of June 4, 2015 and June 4, 2016.

In addition, the vested and outstanding Incentive Distribution Units held by WPX Holdings 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 Holdings also has the ability to similarly convert any of its vested Incentive Distribution Units beginning three years after June 4, 2014. WPX Holdings may not transfer any of the Incentive Distribution Units it holds to any person that is not a controlled affiliate of WPX Energy, Inc.

Income (loss) per unit

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
Net income (loss)	$(52,261)	$(38,474)	$53,068	$(267,328)
Distributions to preferred unitholders	(4,750)	(4,750)	(8,708)	(9,500)
Net loss available to unitholders	(57,011)	(43,224)	44,360	(276,828)
Weighted average number of units outstanding	70,071	68,897	69,518	68,909
Effect of dilutive securities:				
Restricted and phantom units	—	—	—	—
Weighted average units and potential units outstanding	70,071	68,897	69,518	68,909

Basic and diluted income (loss) per unit	$(0.81)	$(0.63)	$0.64	$(4.02)

For the three and six months ended June 30, 2016, 431,691 restricted units and 1,212,692 phantom units 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, 2015, 508,830 restricted units and 862,064 phantom units 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. On June 12, 2015, the unitholders of Legacy approved an amendment to the LTIP to provide for an increase in the number of units available for issuance from 2,000,000 to 5,000,000. The awards under the LTIP may include unit grants, restricted units, phantom units, unit options and unit appreciation rights ("UARs"). As of June 30, 2016, grants of awards net of forfeitures and, in the case of phantom units, historical exercises covering 2,797,391 units had been made, comprised of 266,014 unit option awards, 885,001 restricted unit awards, 1,212,692 phantom unit awards and 433,684 unit awards. The UAR awards and certain phantom unit 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. Because the UARs are settled in cash, Legacy accounts for them 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.

Unit Appreciation Rights

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, 2015, Legacy issued 204,500 UARs to employees which vest ratably over a three-year period and 96,520 UARs to employees which vest at the end of a three-year period. Legacy did not issue UARs to employees during the six-month period ended June 30, 2016. All UARs granted in 2015 expire seven years from the grant date and are exercisable when they vest.

For the six-month periods ended June 30, 2016 and 2015, Legacy recorded $112,100 and $16,359, respectively, of compensation expense due to the change in liability from December 31, 2015 and 2014, respectively, based on its use of the Black-Scholes model to estimate the June 30, 2016 and 2015 fair value of these UARs (see Note 6). As of June 30, 2016, there was a total of approximately $104,048 of unrecognized compensation costs related to the unexercised and non-vested portion of these UARs. At June 30, 2016, this cost was expected to be recognized over a weighted-average period of approximately 2.07 years. Compensation expense is based upon the fair value as of June 30, 2016 and is recognized as a percentage of the service period satisfied. Based on historical data, Legacy has assumed a volatility factor of approximately 81% and employed the Black-Scholes model to estimate the June 30, 2016 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 5.3%. Legacy will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed no annual distribution.

A summary of UAR activity for the six months ended June 30, 2016 is as follows:

Units

		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2016	936,116	$ 20.61	4.91	$ —
Forfeited	(20,667)	20.71		
Outstanding at June 30, 2016	915,449	$ 20.61	4.40	$ —
UARs and unit options exercisable at June 30, 2016	450,456	$ 25.84	2.55	$ —

The following table summarizes the status of Legacy's non-vested UARs since January 1, 2016:

	Non-Vested UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2016	566,067	$ 16.80
Vested	(80,407)	23.07
Forfeited	(20,667)	20.71
Non-vested at March 31, 2016	464,993	$ 15.54

Legacy has used a weighted-average risk-free interest rate of 0.9% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at June 30, 2016 whose terms are consistent with the expected life of the UARs. Expected life represents the period of time that UARs are expected to be outstanding and is based on Legacy's best estimate. The following table represents the weighted-average assumptions used for the Black-Scholes option-pricing model.

	Six Months Ended June 30, 2016
Expected life (years)	4.40
Risk free interest rate	0.9 %
Annual distribution rate per unit	$0.00
Volatility	81.4 %

Phantom Units

Legacy has also issued phantom units under the LTIP to executive officers. A phantom unit is a notional unit that entitles the holder, upon vesting, to receive either one Partnership unit for each phantom unit or the cash equivalent of a Partnership unit, as stipulated by the form of the grant. Legacy is accounting for the phantom units settled in Partnership units by utilizing the equity method. Legacy is accounting for the phantom units settled in cash by utilizing the liability 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 February 24, 2015, the Compensation Committee approved the award of 341,251 subjective, or service-based, phantom units and 259,998 objective, or performance based, phantom units to Legacy’s executive officers.

On June 22, 2016, the Compensation Committee approved with respect to Paul Horne, and the board of directors of LRGPLLC approved the recommendation of the Compensation Committee with respect to the other executive officers the award of a maximum of 391,674 subjective, or service-based, phantom units that, upon vesting, settle in Partnership units, a maximum of 1,286,930 subjective phantom units that, upon vesting, settle in cash and a maximum of 2,238,138 objective, or performance-based, phantom units that, upon vesting, settle in cash to our executive officers.

Compensation expense related to the phantom units was $1.8 million and $1.4 million for the six months ended June 30, 2016 and 2015, respectively.

Restricted Units

During the year ended December 31, 2015, Legacy issued an aggregate of 381,860 restricted units to both non-executive employees and an executive employee. The restricted units awarded to non-executive employees vest ratably over a three-year period beginning at the date of grant. The restricted units granted to the executive employee vest ratably over a three-year period for a portion of the restricted units, with the remainder vesting in full at the end of a five-year period. During the six-month period ended June 30, 2016, Legacy did not issue restricted units to any employees. Compensation expense related to restricted units was $1.6 million and $1.2 million for the six months ended June 30, 2016 and 2015, respectively. As of June 30, 2016, there was a total of $3.2 million of unrecognized compensation expense related to the unvested portion of these restricted units. At June 30, 2016, this cost was expected to be recognized over a weighted-average period of 2.0 years. Pursuant to the provisions of ASC 718, Legacy's issued units, as reflected in the accompanying consolidated balance sheet at June 30, 2016, do not include 431,691 units related to unvested restricted unit awards.

Board Units

On June 15, 2015, Legacy granted and issued 11,025 units to each of its six non-employee directors. The value of each unit was $9.13 at the time of issuance.

On May 10, 2016, Legacy granted and issued 39,526 units to each of its six non-employee directors. The value of each unit was $2.59 at the time of issuance.

(11) Subsidiary Guarantors

On April 2, 2014, Legacy 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, Legacy's 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 remaining $300 million of aggregate principal amount of Legacy's 2021 Senior Notes were subsequently registered through a public exchange offer that closed on February 10, 2015. The 2020 Senior Notes and the 2021 Senior Notes are guaranteed by Legacy's 100% owned subsidiaries Legacy Reserves Operating GP LLC, Legacy Reserves Operating LP, Legacy Reserves Services, Inc., Legacy Reserves Energy Services LLC, Dew Gathering LLC and Pinnacle Gas Treating LLC, which constitute all of Legacy's 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, directly or indirectly, 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.

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 our capital expenditures;
- the level of cash distributions to our limited partners, if any;
- our access to capital including our ability to maintain our borrowing base and customary banking relationships and practices;
- 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, 2015 in Item 1A under “Risk Factors.” The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly.

Overview

The recent supply and demand environment for crude oil and natural gas has resulted in a prolonged period of low commodity prices. Based on the sustained level of commodity prices through the second quarter of 2016, we are experiencing a challenging 2016. Crude oil prices declined from an average of $92.91 per Bbl in 2014 to an average of $39.55 for the six months ended June 30, 2016 and natural gas prices declined from an average of $4.26 per Mcf in 2014 to an average of $2.07 for the six months ended June 30, 2016. If commodity prices persist at current levels, we will continue to experience an adverse effect on our operating income in future periods resulting from decreased revenues and higher depletion rates when compared to prior time periods. However, to illustrate the impact of recent commodity prices on our proved reserves, we recalculated our proved reserves as of December 31, 2015, using the five-year average forward price as of June 30, 2016 for both WTI oil and NYMEX natural gas held constant for the life of our properties. While this 5-year NYMEX forward strip price is not necessarily indicative of our overall outlook on future commodity prices, this commonly used methodology may help provide investors with an understanding of the impact of the recent commodity price environment. Under such assumptions, we estimate our year-end proved reserves increased by approximately 7.6% to 176.6 MMBoe from our previously reported 164.2 MMBoe.

Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce, our access to capital and the amount of our cash distributions, as evidenced by our suspension of cash distributions to our unitholders and holders of our 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") and our 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (together with the Series A Preferred Units, the “Preferred Units”) announced in January 2016. We continue to monitor the commodity markets and their impact on both our distributable cash flow and financial covenants.

Depending on oil and natural gas prices in 2016 and given the recent difficulty we have had entering into new commodity derivative positions with our bank group, we could breach certain financial covenants under our revolving credit facility, which would constitute a default under our revolving credit facility. Such default, if not remedied, would require a waiver from our lenders in order for us to avoid an event of default and subsequent acceleration of all amounts outstanding under our revolving credit facility and potential foreclosure on our oil and natural gas properties. Certain payment defaults or acceleration under our revolving credit facility could cause a cross-default or cross-acceleration of all of our indebtedness. In response to the current commodity price environment, our focus for 2016 is to fund our operations and reduce leverage from both our internally generated cash flow and additional select asset sales. Since December 31, 2015, we have reduced our total leverage by $272.4 million by repurchasing $169.4 million of face amount of our Senior Notes on the open market, exchanging $15.0 million of face amount of our 2020 Senior Notes for units and repaying outstanding amounts under our revolver by $88.0 million.

Because of our 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.

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 portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We have had recent difficulty entering into new commodity derivative positions with our bank group. 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 flow. 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. While gathering and transportation costs are generally borne by the purchasers of our oil and the price paid for our oil reflects these costs, much of our natural gas production is subject to such costs before the transfer of ownership to the purchaser, and we recognize these expenses as operating 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		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$41,272	$59,113	$71,592	$109,409
Natural gas liquids sales	3,922	5,729	6,375	9,921
Natural gas sales	28,173	22,959	61,259	50,010
Total revenue	$73,367	$87,801	$139,226	$169,340
Expenses:				
Oil and natural gas production, excluding ad valorem taxes	$41,520	$42,828	$88,181	$88,772
Ad valorem taxes	$3,041	$2,392	$6,403	$5,668
Total oil and natural gas production	$44,561	$45,220	$94,584	$94,440
Production and other taxes	$3,390	$3,986	$5,963	$8,204
General and administrative, excluding transaction related expenses and LTIP	$7,777	$6,549	$15,469	$14,305
Transaction related expenses	$714	$1,648	$791	$1,673
LTIP expense	$2,502	$2,193	$4,167	$3,281
Total general and administrative	$10,993	$10,390	$20,427	$19,259
Depletion, depreciation, amortization and accretion	$37,668	$36,197	$74,627	$77,265
Commodity derivative cash settlements:				
Oil derivative cash settlements received	$9,760	$27,364	$22,345	$59,564
Natural gas derivative cash settlements received	$12,333	$9,825	$22,525	$17,962
Production:				
Oil (MBbls)	1,039	1,171	2,108	2,371
Natural gas liquids (MGal)	9,663	11,566	17,904	21,252
Natural gas (MMcf)	16,743	9,649	34,009	19,307
Total (MBoe)	4,060	3,055	8,202	6,095
Average daily production (Boe/d)	44,615	33,571	45,066	33,674
Average sales price per unit (excluding derivative cash settlements):				
Oil price (per Bbl)	$39.72	$50.48	$33.96	$46.14
Natural gas liquids price (per Gal)	$0.41	$0.50	$0.36	$0.47
Natural gas price (per Mcf)	$1.68	$2.38	$1.80	$2.59
Combined (per Boe)	$18.07	$28.74	$16.97	$27.78
Average sales price per unit (including derivative cash settlements):				
Oil price (per Bbl)	$49.12	$73.85	$44.56	$71.27
Natural gas liquids price (per Gal)	$0.41	$0.50	$0.36	$0.47
Natural gas price (per Mcf)	$2.42	$3.40	$2.46	$3.52
Combined (per Boe)	$23.51	$40.91	$22.45	$40.50
Average WTI oil spot price (per Bbl)	$45.46	$57.85	$39.55	$53.25
Average Henry Hub natural gas spot price (per Mcf)	$2.15	$2.77	$2.07	$2.82
Average unit costs per Boe:				
Oil and natural gas production, excluding ad valorem taxes	$10.23	$14.02	$10.75	$14.56
Ad valorem taxes	$0.75	$0.78	$0.78	$0.93
Production and other taxes	$0.83	$1.30	$0.73	$1.35
General and administrative excluding transaction related expenses and LTIP	$1.92	$2.14	$1.89	$2.35

Total general and administrative	$2.71	$3.40	$2.49	$3.16
Depletion, depreciation, amortization and accretion	$9.28	$11.85	$9.10	$12.68

Results of Operations

Three-Month Period Ended June 30, 2016 Compared to Three-Month Period Ended June 30, 2015

Our revenues from the sale of oil were $41.3 million and $59.1 million for the three-month periods ended June 30, 2016 and 2015, respectively. Our revenues from the sale of NGLs were $3.9 million and $5.7 million for the three-month periods ended June 30, 2016 and 2015, respectively. Our revenues from the sale of natural gas were $28.2 million and $23.0 million for the three-month periods ended June 30, 2016 and 2015, respectively. The $17.8 million decrease in oil revenues reflects the decrease in average realized price of $10.76 per Bbl (21%) due to a decline in average West Texas Intermediate ("WTI") crude oil prices of $12.39 per Bbl partially offset by an improvement in realized regional differentials. The decrease in oil revenue is also due to natural declines in oil production of 132 MBbls. The $1.8 million decrease in NGL sales reflects a decrease in the realized NGL price of approximately $0.09 per Gal (18%) and a decrease in volumes of 1,903 MGals primarily due to plant downtime in our Mid-Con and Permian properties as well as reduced realizations on our Piceance Basin properties. The $5.2 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 7,094 MMcf (74%), primarily due to our 2015 acquisitions, most notably the acquisitions of East Texas properties (7,642 MMcf), partially offset by natural declines. Average realized natural gas prices decreased by $0.70 per Mcf (29%) during the three months ended June 30, 2016 compared to the same period in 2015 primarily due to the decline in average NYMEX Henry Hub natural gas prices of $0.62 (22%) per Mcf.

For the three-month period ended June 30, 2016, we recorded $37.7 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, 2016 are primarily due to the increase in commodity prices during the second quarter. For the three-month period ended June 30, 2015, we recorded $13.5 million of net losses on oil and natural gas derivatives. Settlements of such contracts resulted in cash receipts of $22.1 million and $37.2 million during the three months ended June 30, 2016 and 2015, respectively.

Our oil and natural gas production expenses, excluding ad valorem taxes, decreased to $41.5 million ($10.23 per Boe) for the three-month period ended June 30, 2016 from $42.8 million ($14.02 per Boe) for the three-month period ended June 30, 2015. This decrease is primarily attributable to cost reduction efforts on historical properties partially offset by additional expenses associated with the East Texas properties acquired in 2015 of $7.5 million. Additionally, production expenses per Boe decreased for the three-month period ended June 30, 2016 compared to the three-month period ended June 30, 2015 due to the inclusion of lower cost production in our East Texas properties acquired in 2015 as well as a reduction in lifting costs in our historical properties. Our ad valorem tax expense increased to $3.0 million ($0.75 per Boe) for the three-month period ended June 30, 2016 compared to $2.4 million ($0.78 per Boe) for the three-month period ended June 30, 2015. The increase was attributable to additional taxes related to our acquisition of East Texas properties partially offset by lower oil and natural gas commodity prices, resulting in lower reserve valuations, upon which much of our ad valorem taxes are based, resulting in lower ad valorem tax expense on a per Boe basis.

Our production and other taxes were $3.4 million and $4.0 million for the three-month periods ended June 30, 2016 and 2015, respectively. Production and other taxes decreased due to the decline in product prices.

Our general and administrative expenses were $11.0 million and $10.4 million for the three-month periods ended June 30, 2016 and 2015, respectively. General and administrative expenses increased $0.6 million primarily due to an increase in LTIP expense and salaries and benefits expense commensurate with a larger asset base as a result of our acquisitions of East Texas properties. This increase was partially offset by general cost reduction efforts.

We incurred depletion, depreciation, amortization and accretion expense, or DD&A, of $37.7 million and $36.2 million for the three-month periods ended June 30, 2016 and 2015, respectively. DD&A increased $1.5 million due primarily to a larger depletable asset base following our acquisition of East Texas properties.

We recorded gain on disposal of assets of $9.1 million and $0.9 million for the three-month periods ended June 30, 2016 and 2015, respectively. The gain in 2016 primarily consisted of dispositions of unproved leasehold acreage.

We recorded interest expense of $20.3 million and $17.8 million for the three-month periods ended June 30, 2016 and 2015, respectively. Interest expense increased approximately $2.5 million primarily due to losses on our interest rate derivatives and interest expense related to additional borrowings on our revolving credit facility to fund the acquisitions of East Texas properties in 2015. This increase was partially offset by decreased interest expense following our repurchase of a portion of our Senior Notes, which resulted in a gain on extinguishment of debt of $20.0 million.

Six-Month Period Ended June 30, 2016 Compared to Six-Month Period Ended June 30, 2015

Our revenues from the sale of oil were $71.6 million and $109.4 million for the six-month periods ended June 30, 2016 and 2015, respectively. Our revenues from the sale of NGLs were $6.4 million and $9.9 million for the six-month periods ended June 30, 2016 and 2015, respectively. Our revenues from the sale of natural gas were $61.3 million and $50.0 million for the six-month periods ended June 30, 2016 and 2015, respectively. The $37.8 million decrease in oil revenues reflects the decrease in average realized price of $12.18 per Bbl (26%) due to a decline in average WTI crude oil prices of $13.70 per Bbl and a decline in production of 263 MBbls due to natural production declines, partially offset by an improvement in realized regional differentials. The $3.5 million decrease in NGL sales reflects a decrease in the realized NGL price of approximately $0.11 per Gal (23%) due to lower commodity prices and a decrease in NGL production of 3,348 MGals (16%), primarily due to ethane rejection in our Piceance Basin properties and plant downtime in our Mid-Con and Permian properties. The $11.2 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 14,702 MMcf (76%) primarily due to 15,544 MMcf of production from our acquired East Texas properties, partially offset by natural production declines. Average realized natural gas prices decreased by $0.79 per Mcf (31%) during the six months ended June 30, 2016 compared to the same period in 2015 due to the decline in average NYMEX Henry Hub natural gas prices of $0.75 per Mcf.

For the six-month period ended June 30, 2016, we recorded $20.6 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, 2016 are primarily due to an increase in commodity prices during 2016 partially offset by cash settlements received, as well as the entrance into new derivative contracts. For the six-month period ended June 30, 2015, we recorded $7.0 million of net gains on oil and natural gas derivatives. Settlements of such contracts resulted in cash receipts of $44.9 million and $77.5 million during the six months ended June 30, 2016 and 2015, respectively.

Our oil and natural gas production expenses, excluding ad valorem taxes, decreased to $88.2 million for the six-month period ended June 30, 2016 from $88.8 million for the six-month period ended June 30, 2015. This decrease was primarily attributable to cost reductions in our historical properties partially offset by additional expenses related to our acquisition of East Texas properties. These reduction efforts, as well as the large volume of natural gas production related to the properties acquired in East Texas resulted in a decrease in the cost per Boe to $10.75 per Boe for the six-month period ended June 30, 2016 from $14.56 per Boe for the six-month period ended June 30, 2015. Our ad valorem tax expense increased to $6.4 million ($0.78 per Boe) for the six-month period ended June 30, 2016 compared to $5.7 million ($0.93 per Boe) for the six-month period ended June 30, 2015 primarily due to additional taxes related to our acquisition of East Texas properties partially offset by lower oil and natural gas commodity prices, resulting in lower reserve valuations, upon which much of our ad valorem taxes are based, resulting in a lower cost per Boe.

Our production and other taxes were $6.0 million and $8.2 million for the six-month periods ended June 30, 2016 and 2015, respectively. Production and other taxes decreased because of the decline in product prices.

Our general and administrative expenses were $20.4 million and $19.3 million for the six-month periods ended June 30, 2016 and 2015, respectively. General and administrative expenses primarily increased due to overall general and administrative increases associated with a larger asset base and a $0.9 million non-cash increase in LTIP expense.

We incurred depletion, depreciation, amortization and accretion expense, or DD&A, of $74.6 million and $77.3 million for the six-month periods ended June 30, 2016 and 2015, respectively. DD&A decreased $2.6 million due primarily to lower depletion across much of our asset base due to the reduced depletable basis resulting from the significant impairment realized in 2015 and 2016 partially offset by inclusion of properties acquired in East Texas.

Impairment expense was $15.4 million and $209.4 million for the six-month periods ended June 30, 2016 and 2015, respectively. In the six-month period ended June 30, 2016, we recognized $15.4 million of impairment expense on twelve separate producing fields primarily related to the further decline in oil and natural gas futures prices during the period. Impairment expense for the period ended June 30, 2015 was recognized on thirty-three separate producing fields primarily related to the decline in natural gas prices. We recognized significant impairment expense in the fourth quarter of 2014, and the continued decline in natural gas futures prices during the first quarter of 2015 resulted in additional write-downs.

We recorded (gain) loss on disposal of assets of $(40.8) million and $1.0 million for the six-month periods ended June 30, 2016 and 2015, respectively. The gain in 2016 primarily consisted of dispositions of unproved leasehold acreage.

We recorded interest expense of $45.5 million and $35.6 million for the six-month periods ended June 30, 2016 and 2015, respectively. Interest expense increased approximately $9.9 million primarily due to interest expense related to additional borrowings on our revolving credit facility to fund the acquisition of East Texas properties and losses on our interest rate derivatives. This increase was partially offset by decreased interest expense following our repurchase of a portion of our Senior Notes, which resulted in a gain on extinguishment of debt of $150.8 million.

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;
- (Gain) loss on extinguishment of debt
- Income tax expense (benefit);
- Depletion, depreciation, amortization and accretion;
- Impairment of long-lived assets;
- (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;
- Equity in EBITDA of equity method investee;
- Net (gains) losses on commodity derivatives;
- Net cash settlements received (paid) on commodity derivatives;
- Transaction related expenses.

The following table presents a reconciliation of our consolidated net loss to Adjusted EBITDA for the three and six months ended June 30, 2016 and 2015, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
Net income (loss)	$(52,261)	$(38,474)	$53,068	$(267,328)
Plus:				
Interest expense	20,302	17,760	45,478	35,552
Gain on extinguishment of debt	(19,998)	—	(150,802)	—
Income tax expense (benefit)	87	456	487	(291)
Depletion, depreciation, amortization and accretion	37,668	36,197	74,627	77,265
Impairment of long-lived assets	—	—	15,447	209,402
(Gain) loss on disposal of assets	(9,141)	(934)	(40,842)	1,007
Equity in (income) loss of equity method investees	9	(24)	14	(103)
Unit-based compensation expense	2,502	2,193	4,167	3,281
Minimum payments earned in excess of overriding royalty interest(a)	—	377	802	744
Equity in EBITDA of equity method investee(b)	—	50	—	169
Net (gains) losses on commodity derivatives	37,675	13,497	20,637	(6,983)
Net cash settlements received on commodity derivatives	22,093	37,189	44,870	77,526
Transaction related expenses	714	1,648	791	1,673
Adjusted EBITDA	$39,650	$69,935	$68,744	$131,914

(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. We divested our interest in this investee in May of 2015.

For the three months ended June 30, 2016 and 2015, respectively, Adjusted EBITDA decreased 43% to $39.7 million from $69.9 million. For the six months ended June 30, 2016 and 2015, respectively, Adjusted EBITDA decreased 48% to $68.7 million from $131.9 million. These decreases can be attributed to the significant declines in commodity prices and lower commodity derivative settlements and were partially offset by production from our East Texas properties acquired in 2015.

Capital Resources and Liquidity

Our primary sources of capital and liquidity have been cash flow from operations, sale of oil and natural gas properties, 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 indebtedness.

Based upon current oil and natural gas price expectations and our commodity derivatives positions, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient liquidity to fund our operations for the remainder of 2016 including our planned capital expenditures of $37 million. However, depending on oil and natural gas prices in 2016, we could breach certain financial covenants under our revolving credit facility, which would constitute a default under our revolving credit facility. Such a default, if not remedied, would require a waiver from our lenders in order for us to avoid an event of default and potential subsequent acceleration of all amounts outstanding under our revolving credit facility and potential foreclosure on our oil and natural gas properties. Certain payment defaults or acceleration under our revolving credit facility could cause a cross-default or cross-acceleration of all of our other indebtedness. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we will not have sufficient liquidity to repay all of our outstanding indebtedness. In light of this, we elected to suspend distributions to unitholders and distributions to the holders of our Preferred Units. Additionally, we have consummated certain credit-accretive asset sales comprised primarily of non-producing acreage and have used the proceeds of such asset sales to reduce total leverage. Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. We have recently had difficulty entering into new commodity derivative positions with our bank group, which has restricted our ability to mitigate commodity price risk. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to operate or to maintain planned levels of capital expenditures. For further information about our revolving credit facility, please refer to Note 2—Long-Term Debt in the Notes to Condensed Consolidated Financial Statements.

The amounts available for borrowing under our credit facility are subject to a borrowing base, which is currently set at $630 million. As of August 3, 2016, we had $108.6 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 about October 2016, subject to the parties' rights to have additional redeterminations between scheduled redeterminations. Please see “—Cash Flow from Financing Activities—Credit Facility.”

Our commodity derivatives position, which we use to mitigate commodity price volatility and, if positive, support our borrowing capacity, resulted in $132.9 million of cash receipts in the year ended December 31, 2015. However, while a significant portion of our projected oil and natural gas production is covered by derivative contracts, such contracts are at a price point that is significantly lower than our historical contracts. As a point of reference, assuming NYMEX oil and natural gas prices of $50.00 per Bbl and $2.50 per Mcf, respectively, for the remainder of 2016, we would anticipate receiving total cash receipts of approximately $70.0 million for the calendar year 2016, representing an approximately $62.9 million reduction from 2015.

For an example illustrating the potential effects of commodity prices on our estimates of proved reserves, see “Management’s Discussion and Analysis of Financial Condition—Overview.”

As market conditions warrant, we may, subject to certain limitations and restrictions, repurchase, exchange or otherwise pay down our outstanding debt, including our Senior Notes, in open market transactions, privately negotiated transactions, by tender offer or otherwise which may impact the trading liquidity of such securities. The amounts involved in any such transactions, individually or in the aggregate, may be material. Since December 31, 2015, we have repurchased approximately $169.4 million of face amount of our Senior Notes on the open market and have exchanged 2,719,124 units representing limited partner interests in the Partnership for $15.0 million of face amount of our 2020 Senior Notes. Our recently redetermined borrowing base of $630 million currently prohibits additional Senior Notes repurchases given we no longer meet the required minimum liquidity levels.

A significant portion of our horizontal operated development activity in the Permian Basin is pursued through our development agreement (the "Development Agreement") with Jupiter JV LP ("Investor"), an affiliate of TPG Special Situations Partners' investment funds. Pursuant to the Development Agreement, Investor funds 95% of the costs to the parties' combined interests to develop the assets and 80% of the costs to the parties' combined interests to develop or construct associated saltwater disposal wells and other infrastructure assets. Investor received an undivided 87.5% of our working interest in the assets, subject to reversions upon the occurrence of certain events. Legacy’s capital resources and liquidity benefit from its interest in the development activity under the Development Agreement.

Cash Flow from Operations

Our net cash provided by or (used in) operating activities was $(14.6) million and $0.2 million for the six-month periods ended June 30, 2016 and 2015, respectively. The 2016 period was impacted by lower realized commodity prices.

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.

Cash Flow from Investing Activities

We invested $14.1 million of capital for the six-month period ended June 30, 2016, which consisted of $11.7 million for development projects, $2.2 million for adjustments to prior period acquisitions and $0.2 million for immaterial acquisitions. We received $87.5 million of proceeds related to the divestiture of various oil and natural gas properties. Our cash capital expenditures were $23.7 million for the six-month period ended June 30, 2015. The 2015 total includes $1.9 million for the acquisition of oil and natural gas properties in individually immaterial acquisitions as well as $21.8 million for development projects.

Our annual capital expenditure budget for 2016, which predominantly consists of drilling, CO_2 injection, recompletion and well stimulation projects, was set at $37.0 million. During the six months ended June 30, 2016 we have spent $11.7 million. 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. Our remaining borrowing capacity under our revolving credit facility is $108.6 million as of August 3, 2016. 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. 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. We use derivatives to offset price volatility of oil and natural gas prices. For the six-month periods ended June 30, 2016 and 2015, we had favorable settlements of $44.9 million and $77.5 million, respectively, related to our commodity derivatives.

By reducing the cash flow effects of price volatility from a 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, none of our current counterparties require us to post margin. 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 August 1, 2016, covering the period from July 1, 2016 through December 31, 2019. 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 prices of natural gas.

Oil Swaps:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2016	1,002,800	$55.24	$50.15-$91.00
2017	182,500	$84.75	$84.75

Natural Gas Swaps:

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
July-December 2016	24,973,600	$3.01	$2.42-$5.30

2017	27,600,000	$3.36	$3.29 - $3.39
2018	27,600,000	$3.36	$3.29 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

We have entered into regional crude oil differential swap contracts in which we have swapped the floating WTI-ARGUS (Midland) crude oil price for floating WTI-ARGUS (Cushing) crude oil price less a fixed-price differential. As noted above, we receive a discount to the NYMEX WTI crude oil price at the point of sale. Due to refinery downtime and limited takeaway capacity that has impacted the Permian Basin, the difference between the WTI-ARGUS (Midland) price, which is the price we receive on almost all of our Permian crude oil production, and the WTI-ARGUS (Cushing) price reached historic highs in late 2012 and early 2013 and again in late 2014. We entered into these differential swaps to negate a portion of this volatility. The following table summarizes the oil differential contracts currently in place as of August 1, 2016, covering the period from July 1, 2016 through December 31, 2017:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2016	1,472,000	$(1.60)	$(1.50)-$(1.75)
2017	2,190,000	$(0.30)	$(0.05)-$(0.75)

We have also entered into multiple NYMEX WTI crude oil costless collar contracts. Each contract combines a long put option or "floor" with a short call option or "ceiling." At an annual WTI market price of $40.00, $50.00 and $60.00, the summary position below would result in a net price of $45.00, $50.00 and $58.89, respectively.

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl
2017	1,460,000	$45.00	$58.89

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. For example, at an annual average WTI market price of $40.00, the summary positions below would result in a net price of $65.00 for the remainder of 2016 and 2017. The following table summarizes the three-way oil collar contracts currently in place as of August 1, 2016, covering the period from July 1, 2016 through June 30, 2017:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
July-December 2016	230,000	$60.00	$85.00	$102.46
2017	72,400	$60.00	$85.00	$104.20

We have also entered into multiple NYMEX WTI crude oil derivative enhanced swap contracts. The 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. For example, at an annual average WTI market price of

$40.00, the summary positions below would result in a net price of $66.70, $65.85 and $65.50 for the remainder of 2016, 2017 and 2018, respectively. The following table summarizes this type of enhanced swap contracts currently in place as of August 1, 2016, covering the period from January 1, 2016 to December 31, 2018:

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
July-December 2016	92,000	$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 multiple NYMEX Henry Hub natural gas costless collar contracts. Each contract combines a long put option or "floor" with a short call option or "ceiling." At an annual Henry Hub price of $2.50, $3.00 and $3.50, the summary position below would result in a net price of $2.90, $3.00 and $3.44, respectively.

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl
2017	14,600,000	$2.90	$3.44

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. For example, at an annual average Henry Hub market price of $2.50, the summary positions below would result in a net price of $3.00 for the remainder of 2016 and 2017. The following table summarizes the three-way natural gas collar contracts currently in place as of August 1, 2016, covering the period from July 1, 2016 to December 31, 2017:

Time Period	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
July-December 2016	2,790,000	$3.75	$4.25	$5.08
2017	5,040,000	$3.75	$4.25	$5.53

As of August 1, 2016, Legacy had the following Henry Hub NYMEX to Northwest Pipeline, California SoCal NGI and San Juan Basin 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:

	July-December 2016		2017	
	Volumes (MMBtu)	Average Price per MMBtu	Volumes (MMBtu)	Average Price per MMBtu
NWPL	7,529,832	$(0.19)	7,300,000	$(0.16)
SoCal	—	$—	2,500,250	$0.11
San Juan	1,256,720	$(0.16)	2,500,250	$(0.10)

Cash Flow from Financing Activities

Our net cash used in financing activities was $104.2 million for the six months ended June 30, 2016, compared to $51.7 million for the six months ended June 30, 2015. During the six months ended June 30, 2016, total net payments to our revolving credit facility were $75.0 million. We had cash outflow during the six months ended June 30, 2016 in the amount of $21.5 million for repurchases of our Senior Notes on the open market.

During the six months ended June 30, 2015, total net borrowings under our revolving credit facility were $26.0 million. The proceeds from our net borrowings were used to finance our acquisition and development activities as well as to fund a portion of our distributions to unitholders. We had cash outflow during the six months ended June 30, 2015 of $66.6 million for distributions to record holders of our units and $9.5 million for distributions to record holders of our Preferred Units, a portion of which was funded from cash flow from operations with the remainder funded from borrowings under our revolving credit facility.

Credit Facility

On April 1, 2014, we entered into a five-year $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent (the “Current Credit Agreement”). Borrowings under the Current Credit Agreement mature on April 1, 2019. Our obligations under the Current Credit Agreement are secured by mortgages on over 90% 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.

As of June 30, 2016, we were in compliance with all covenants of the Current Credit Agreement. Depending on oil and natural gas prices in 2016, we could breach certain financial covenants under our revolving credit facility, which would constitute a default under our revolving credit facility. Such default, if not remedied, would require a waiver from our lenders in order for us to avoid an event of default and subsequent acceleration of all amounts outstanding under our revolving credit facility and potential foreclosure on our oil and natural gas properties. As previously noted, if the lenders under our revolving credit facility were to accelerate the indebtedness under our revolving credit facility as a result of a default, such acceleration could cause a cross-default of all of our other outstanding indebtedness, including our Senior Notes, and permit the holders of such indebtedness to accelerate the maturities of such indebtedness. While no assurances can be made that, in the event of a covenant breach, such a waiver will be granted, we believe the long-term global outlook for commodity prices and our efforts to date, which include the suspension of distributions to our unitholders and Preferred Unitholders, as well as asset sales completed and anticipated as of the date of this filing, will be viewed positively by our lenders. If an event of default would occur and were continuing, we would be unable to make borrowings under the Current Credit Agreement, may be unable to make distributions to our unitholders and our financial condition and liquidity would be adversely affected. For further information related to our Current Credit Agreement, please refer to Note 2–Long-Term Debt in the Notes to Condensed Consolidated Financial Statements.

As of June 30, 2016, Legacy had approximately $533 million drawn under the Current Credit Agreement at a weighted average interest rate of 3.22%, leaving approximately $95.6 million of availability under the Current Credit Agreement. For the six-month period ended June 30, 2016, Legacy paid in cash $9.3 million of interest expense on the Current Credit Agreement.
We periodically enter into interest rate swap transactions to mitigate the volatility of interest rates. As of June 30, 2016, we had interest rate swaps on notional amounts of $350 million with a weighted average fixed rate of 1.20%. These swaps mature between September 2017 and September 2019.

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 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.

During the six months ended June 30, 2016, we repurchased a face amount of $52.0 million of our 2020 Senior Notes on the open market and exchanged 2,719,124 units representing limited partner interests in the Partnership for $15.0 million of face amount of our 2020 Senior Notes.

As of June 30, 2016, we were in compliance with all financial and other covenants of the 2020 Senior Notes. If an event of default would occur and were continuing, we would be unable to pay distributions to our unitholders. As previously noted, if the lenders under our revolving credit facility were to accelerate the indebtedness under our revolving credit facility as a result of a default, such acceleration could cause a cross-default of all of our other outstanding indebtedness and permit the holders of such indebtedness to accelerate the maturities of such indebtedness. For further information related to our 2020 Senior Notes please refer to Note 2–Long-Term Debt in the Notes to Condensed Consolidated Financial Statements.

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 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, 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 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. We received approximately $291.8 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by us.

During the six months ended June 30, 2016, we repurchased a face amount of $117.4 million of our 2021 Senior Notes on the open market.

As of June 30, 2016, we were in compliance with all financial and other covenants of the 2021 Senior Notes. If an event of default would occur and were continuing, we would be unable to pay distributions to its unitholders. As previously noted, if the lenders under our revolving credit facility were to accelerate the indebtedness under our revolving credit facility as a result of a default, such acceleration could cause a cross-default of all of our other outstanding indebtedness and permit the holders of such indebtedness to accelerate the maturities of such indebtedness. For further information related to our 2021 Senior Notes please refer to Note 2–Long-Term Debt in the Notes to Condensed Consolidated Financial Statements.

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, 2016, our critical accounting policies were consistent with those discussed in our Annual Report on Form 10-K for the period ended December 31, 2015.

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 February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2016-02, Leases ("ASU 2016-02"). ASU 2016-02 establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are currently evaluating the impact of our pending adoption of ASU 2016-02 on our consolidated financial statements.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, "Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern" (“ASU 2014-15”). ASU 2014-15 requires management to assess an entity’s ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. The standard is effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016, with early adoption permitted. We are currently evaluating the provisions of ASU 2014-15 and do not anticipate any impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 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. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers" ("ASU 2015-14"), which approved a one-year delay of the standard's effective date. In accordance with ASU 2015-14, the standard is now effective for annual periods beginning after December 15, 2017, 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 do not anticipate the standard will have a material impact on our consolidated financial statements.

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 have recently had difficulty entering into new commodity derivative positions with our bank group, which has restricted our ability to mitigate commodity price risk. We do not hold or issue derivative instruments for speculative trading purposes.

As of June 30, 2016, the fair value of our commodity derivative positions was a net asset of $52.9 million based on NYMEX futures prices from July 2016 to December 2019 for both oil and natural gas. As of December 31, 2015, the fair market value of our commodity derivative positions was a net asset of $118.4 million based on NYMEX futures prices from January 2016 to December 2019 for both oil and natural gas. While a significant portion of our projected oil and natural gas production is covered by derivative contracts, such contracts are at a price point that is significantly lower than our historical contracts. As a point of reference, assuming NYMEX oil and natural gas prices of $50.00 per Bbl and $2.50 per Mcf, respectively, for the remainder of 2016, we would anticipate receiving total cash receipts of approximately $70.0 million for the calendar year 2016, representing an approximately $62.9 million reduction from 2015. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives from July 2016 through December 2019, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Cash Flow from Investing Activities.”

Interest Rate Risks

At June 30, 2016, we had debt outstanding under our revolving credit facility of $533 million, which incurred interest at floating rates in accordance with our revolving credit facility. The average annual interest rate incurred by us under our revolving credit facility for the six-month period ended June 30, 2016 was 3.2%. A 1% increase in LIBOR on our outstanding debt under our revolving credit facility as of June 30, 2016 would result in an estimated $1.83 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 1.20% to mitigate the volatility of interest rates on notional amounts of $350 million of floating rate debt.

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, 2016. 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, 2016, 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, 2015, 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.

Tax Risks to Unitholders and Preferred Unitholders

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders are treated as partners that are allocated a share of our taxable income irrespective of the amount of cash, if any, distributed by us, unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, including our taxable income associated with cancellation of debt ("COD income") or a disposition of property by us, even if they receive no cash distributions from us. As of January 21, 2016, we have suspended all cash distributions to unitholders and monthly cash distributions to holders of our preferred units.

We may engage in transactions to de-lever the Partnership and manage our liquidity that may result in the allocation of income and gain to our unitholders without a corresponding cash distribution. For example, during the six month period ended June 30, 2016, we closed 18 divestitures generating net proceeds of $87.5 million, and we may sell additional assets and use the proceeds to repay existing debt or fund capital expenditure, in which case our unitholders may be allocated taxable income and gain resulting from the sale, all or a portion of which may be subject to recapture rules and taxed as ordinary income rather than capital gain, without receiving a cash distribution. Further, we may pursue other opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications that would result in COD income being allocated to our unitholders as ordinary taxable income. For example, in 2016 we have repurchased and exchanged approximately $184.4 million of our existing debt at prices lower than face amount (see "Footnote 2—Long-Term Debt"). These repurchases will, and similar transactions in the future may, result in COD income that will be allocated to our unitholders as ordinary taxable income with no corresponding cash distribution to pay the resulting tax liability. A unitholder who has held units for a long period of time likely will have been allocated net tax losses, some of which may have been suspended. Such losses should be available to offset any COD income, either in whole or in part. However, a unitholder who has held units for only a short period of time will likely not have sufficient losses allocated to them to offset any COD income.

The ultimate effect of any income allocations will depend on the unitholder's individual tax position, including the availability of any current or suspended passive losses that may offset some portion of the COD income allocable to a unitholder. Unitholders are encouraged to consult their tax advisors with respect to the consequences of potential transactions that may result in income and gain to unitholders.

Tax gain or loss on the disposition of our units could be more or less than expected because prior distributions in excess of allocations of income will decrease our unitholders tax basis in their units.

If our unitholders sell any of their units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those units. Prior distributions to unitholders that in the aggregate exceeded the cumulative net taxable income they were allocated for a unit, decreased the tax basis in that unit, and will, in effect, become taxable income to our unitholders if the unit is sold at a price greater than their tax basis in that unit, even if the price received is less than original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders due to the potential recapture items, including depreciation, depletion and intangible drilling cost recapture. In addition, because the amount realized may include a unitholder’s share of our nonrecourse liabilities, if they sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to unitholders or for other uses.

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our general partner and unitholders with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders or for other uses may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

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

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 2, 2016	12,792(1)	$2.67	—	—
May 19, 2016	25,379(2)	$2.50	—	—

(1) These units were purchased by the Partnership in satisfaction of certain employee tax withholding obligations at a price of $2.67 per unit, the closing price of Legacy's units on the NASDAQ Global Market on May 2, 2016.
(2) These units were purchased by the Partnership in satisfaction of certain employee tax withholding obligations at a price of $2.50 per unit, the closing price of Legacy's units on the NASDAQ Global Market on May 19, 2016.

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, as amended by Amendment No. 1 thereto, dated May 10, 2016
3.3	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.4	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
3.5	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)
3.6	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)
10.1	Form of Grant of Phantom Units Under Objective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP’s Current Report on Form 8-K (File No. 001-33249) filed June 17, 2016, Exhibit 10.1)
10.2	Form of Grant of Phantom Units (Cash) Under Subjective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP’s Current Report on Form 8-K (File No. 001-33249) filed June 17, 2016, Exhibit 10.2)
10.3	Form of Grant of Phantom Units (Units) Under Subjective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP’s Current Report on Form 8-K (File No. 001-33249) filed June 17, 2016, Exhibit 10.3)
10.4	Form of Retention Bonus Agreement (Incorporated by reference to Legacy Reserves LP’s Current Report on Form 8-K (File No. 001-33249) filed June 17, 2016, Exhibit 10.4)
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 Extension Definition Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB**	XBRL Taxonomy Extension 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 3, 2016	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)