Legacy Reserves LP Announces Third Quarter 2016 Results and Provides Operational and Financial Update

MIDLAND, Texas, November 2, 2016- (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced third quarter results for 2016 including the following Q3 highlights:

- Reduced lease operating expenses, excluding ad valorem taxes, to $40.1 million representing a 3% decrease compared to Q2 2016 and a 17% decrease compared to Q4 2015
- Closed an additional $8.0 million of asset sales, bringing our year-to-date as of September 30, 2016 total divestitures to $95.5 million
- Closed on $6.6 million of acquisitions of Permian acreage with horizontal potential and infrastructure assets to improve our operational efficiencies in our development program
- Further reduced debt outstanding by $17.0 million

Operational Update

Through Q3 2016, we have spent $18.5 million of our $37 million 2016 capital budget representing a year to date spend of 50% of the budgeted total. Approximately 17% was spent on recompletions and workovers in our East Texas region. The majority of the balance was deployed in the Permian on workovers and on horizontal development under our development agreement with an affiliate of TPG Special Situations Partners ("TSSP") under which we operate all wells and fund 5% of the parties' development capital. Since September 2015, we have drilled and completed 13 horizontal wells under the program: 6 in Lea County, NM, 1 in Southern Reagan County, TX and 6 in Howard County, TX. In addition, we are currently in process with another 8 wells under the program which we expect will be online sometime in late 2016 and early 2017.

2016 Asset Sales Update

Through Q3 2016, we have closed 23 divestitures generating net proceeds of $95.5 million. Below are the summary statistics of such sales:

Transaction Statistics:

Total Sales Price	$	95,485,454
Transaction Count		23
County Count		67
Total Net Acreage		72,000
Midland Basin Net Acreage		9,930
Average Gross Midland Basin Tract Size (acres)		184
Production (Boe/d) (1)		1,207
Cash Flow (1)	$	(588,750)
Total Gross Well Count (2)		914
YE 2015 PUDs		3
$ / Net Midland Basin Acre (3)	$	7,982

(1) Estimate based on last twelve months prior to closing each transaction.
(2) Includes producing, injecting and shut-in wells and PUD locations.
(3) Calculated as sales price received attributable to Midland Basin acreage divided by Midland Basin acreage.

In October, we completed two additional divestments of properties for approximately $0.6 million, bringing our year-to-date total to $96.1 million. We do not anticipate any additional significant asset sales under this initiative.

Capital Structure Update

As announced on October 25, 2016, we recently drew $60 million of new second lien term loans under a second lien term loan credit facility with GSO Capital Partners L.P. ("GSO") providing for term loans up to an aggregate principal amount of $300.0 million. Proceeds (net of transaction fees and expenses) from such draw were utilized to repay borrowings under our revolving credit facility. We may use the remaining $240 million balance within twelve months of closing for general corporate purposes and for the repayment of outstanding indebtedness. The second lien term loan will be issued with an upfront fee of 2% and bear interest at a rate of 12.00% per annum with a maturity date, subject to certain conditions, of August 31, 2021.

Through October 31, 2016, we have reduced our year-end 2015 total debt outstanding by $284.4 million. Our debt balances as of each of the respective dates are as follows:

	12/31/2015	9/30/2016	10/31/2016
	(In thousands)		
Credit Facility due 2019 (1)	$ 608,000	$ 516,000	$ 448,000
Second Lien Term Loan due 2021 (1) (2)	—	—	60,000
8% Senior Notes (1) (2)	300,000	232,989	232,989
6.625% Senior Notes (1) (2)	550,000	432,656	432,656
Total Debt Outstanding (1) (2)	$ 1,458,000	$ 1,181,645	$ 1,173,645

(1) Excludes unamortized financing costs.
(2) Excludes unamortized discount.

Given our recently redetermined borrowing base of $600 million, outstanding borrowings of $448 million and $1.4 million of outstanding letters of credit, we currently have $150.6 million of availability under our revolving credit facility.

Near-Term Outlook and Commentary

Paul T. Horne, Chairman, President and Chief Executive Officer of Legacy's general partner commented, “Legacy has continued to take steps to improve our positioning in this difficult downturn. Our development program with TSSP continues to deliver strong asset-level results. Despite our minimal capital spend this year, our employees have been engineering, operating and supporting a $180 million gross capital program. Their remarkable execution and ability to drive down costs have sustained us and the work being done today should bear fruit tomorrow. With the new addition of GSO’s second lien term loan, we look forward to finding and taking additional steps to take to enhance equity value.”

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 38,751	$ 49,779	$ 110,343	$ 159,188
Natural gas liquids sales	3,457	2,946	9,832	12,867
Natural gas sales	41,332	36,773	102,591	86,783
Total revenue	$ 83,540	$ 89,498	$ 222,766	$ 258,838
Expenses:				
Oil and natural gas production, excluding ad valorem taxes	$ 40,118	$ 45,954	$ 128,299	$ 134,726
Ad valorem taxes	$ 3,003	$ 2,492	$ 9,406	$ 8,160
Total oil and natural gas production	$ 43,121	$ 48,446	$ 137,705	$ 142,886
Production and other taxes	$ 3,986	$ 4,834	$ 9,949	$ 13,038
General and administrative, excluding trans. related costs and LTIP	$ 7,490	$ 8,040	$ 22,959	$ 22,345
Transaction related costs	$ 296	$ 6,502	$ 1,087	$ 8,176
LTIP expense	$ 1,445	$ 1,704	$ 5,612	$ 4,985
Total general and administrative	$ 9,231	$ 16,246	$ 29,658	$ 35,506
Depletion, depreciation, amortization and accretion	$ 36,068	$ 45,041	$ 110,695	$ 122,306
Commodity derivative cash settlements:				
Oil derivative cash settlements received	$ 8,089	$ 17,092	$ 30,434	$ 76,656
Natural gas derivative cash settlements received	$ 3,524	$ 9,696	$ 26,049	$ 27,658
Production:				
Oil (MBbls)	962	1,149	3,070	3,520
Natural gas liquids (MGal)	9,742	10,084	27,646	31,336
Natural gas (MMcf)	16,572	14,383	50,581	33,689
Total (MBoe)	3,956	3,786	12,158	9,881
Average daily production (Boe/d)	43,000	41,152	44,372	36,194
Average sales price per unit (excluding derivative cash settlements):				
Oil price (per Bbl)	$ 40.28	$ 43.32	$ 35.94	$ 45.22
Natural gas liquids price (per Gal)	$ 0.35	$ 0.29	$ 0.36	$ 0.41
Natural gas price (per Mcf)	$ 2.49	$ 2.56	$ 2.03	$ 2.58
Combined (per Boe)	$ 21.12	$ 23.64	$ 18.32	$ 26.20
Average sales price per unit (including derivative cash settlements):				
Oil price (per Bbl)	$ 48.69	$ 58.20	$ 45.86	$ 67.00
Natural gas liquids price (per Gal)	$ 0.35	$ 0.29	$ 0.36	$ 0.41
Natural gas price (per Mcf)	$ 2.71	$ 3.23	$ 2.54	$ 3.40
Combined (per Boe)	$ 24.05	$ 30.71	$ 22.97	$ 36.75
Average WTI oil spot price (per Bbl)	$ 44.85	$ 46.49	$ 41.35	$ 50.94
Average Henry Hub natural gas index price (per MMbtu)	$ 2.88	$ 2.76	$ 2.34	$ 2.80
Average unit costs per Boe:				
Oil and natural gas production, excluding ad valorem taxes	$ 10.14	$ 12.14	$ 10.55	$ 13.63
Ad valorem taxes	$ 0.76	$ 0.66	$ 0.77	$ 0.83
Production and other taxes	$ 1.01	$ 1.28	$ 0.82	$ 1.32
General and administrative excluding trans. related costs and LTIP	$ 1.89	$ 2.12	$ 1.89	$ 2.26
Total general and administrative	$ 2.33	$ 4.29	$ 2.44	$ 3.59
Depletion, depreciation, amortization and accretion	$ 9.12	$ 11.90	$ 9.10	$ 12.38

Financial and Operating Results - Three-Month Period Ended September 30, 2016 Compared to Three-Month Period Ended September 30, 2015

- Production increased 4% to 43,000 Boe/d from 41,152 Boe/d primarily due to our East Texas acquisitions that only had a partial quarter contribution to Q3 2015. These increases were partially offset by declines in our oil production driven by asset divestitures and natural production declines.

- Average realized price, excluding net cash settlements from commodity derivatives, decreased 11% to $21.12 per Boe in 2016 from $23.64 per Boe in 2015 driven by the significant decline in commodity prices as well as the increase of natural gas production as a percentage of total production. Average realized oil price decreased 7% to $40.28 in 2016 from $43.32 in 2015 driven by a decrease in the average West Texas Intermediate ("WTI") crude oil price of $1.64 per Bbl and worsening regional differentials. Average realized natural gas price decreased 3% to $2.49 per Mcf in 2016 from $2.56 per Mcf in 2015. This decrease is primarily a result of the decrease in realized price in our Piceance Basin properties partially offset by the increase in average Henry Hub natural gas index price of $0.12 per Mcf and improvements in regional differentials. Finally, our average realized NGL price increased 21% to $0.35 per gallon in 2016 from $0.29 per gallon in 2015.

- Production expenses, excluding ad valorem taxes, decreased 13% to $40.1 million in 2016 from $46.0 million in 2015, primarily due to cost reduction efforts on historical properties and asset divestitures, partially offset by production expenses related to our acquisition of East Texas properties ($5.0 million). On an average cost per Boe basis, production expenses excluding ad valorem taxes decreased 16% to $10.14 per Boe in 2016 from $12.14 per Boe in 2015, driven primarily by cost reduction efforts in our historical properties.

- General and administrative expenses, excluding unit-based Long-Term Incentive Plan compensation expense decreased to $7.8 million in 2016 from $14.5 million in 2015, reflecting a reduction in transaction related costs.

- Cash settlements received on our commodity derivatives during 2016 were $11.6 million compared to $26.8 million in 2015. While commodity prices were lower in 2016, the decline in cash settlements received is a result of the reduced nominal volumes hedges in Q3 2016 compared to Q3 2015 and a lower weighted average hedge price.

- Total development capital expenditures decreased to $6.9 million in 2016 from $7.9 million in 2015. The 2016 activity was comprised mainly of the drilling and completion of joint development agreement wells, East Texas recompletions and workovers and capital costs related to CO_2 properties.

Financial and Operating Results - Nine-Month Period Ended September 30, 2016 Compared to Nine-Month Period Ended September 30, 2015

- Production increased 23% to 44,372 Boe/d from 36,194 Boe/d primarily due to acquisitions in the second half of 2015 including the acquisition of East Texas properties. These increases were partially offset by declines in our oil production driven by asset divestitures and natural production declines.

- Average realized price, excluding net cash settlements from commodity derivatives, decreased 30% to $18.32 per Boe in 2016 from $26.20 per Boe in 2015 driven by the significant decline in commodity prices as well as the increase in NGL and natural gas production as a percentage of total production. Average realized oil price decreased 21% to $35.94 in 2016 from $45.22 in 2015 driven by a decrease in the average WTI crude oil price of $9.59 per Bbl. Average realized natural gas price decreased 21% to $2.03 per Mcf in 2016 from $2.58 per Mcf in 2015. This decrease is a result of the decrease in the average Henry Hub natural gas index price of approximately $0.46 per Mcf. Finally, our average realized NGL price decreased 12% to $0.36 per gallon in 2016 from $0.41 per gallon in 2015. This decrease is due to lower commodity prices.

- Despite additional expenses from our acquisition of East Texas properties of approximately $19.8 million, our production expenses, excluding ad valorem taxes, decreased 5% to $128.3 million in 2016 from $134.7 million in 2015. On an average cost per Boe basis, production expenses decreased 23% to $10.55 per Boe in 2016 from $13.63 per Boe in 2015. These significant savings were driven primarily by expense reduction efforts across our historical property set ($26.2 million) as well as the inclusion of lower cost natural gas properties acquired in East Texas.

- Non-cash impairment expense totaled $20.1 million driven by the continued decline in commodities futures prices during 2016 and well performance.

- General and administrative expenses, excluding unit-based LTIP compensation expense totaled $24.0 million in 2016 compared to $30.5 million in 2015, reflecting a reduction in transaction related costs partially offset by increases in salaries and wages commensurate with a larger asset base following our acquisition of East Texas properties.

- Cash settlements received on our commodity derivatives during 2016 were $56.5 million compared to $104.3 million in 2015. While commodity prices were lower in 2016, the decline in cash settlements received is a result of the reduced nominal volumes hedged in Q3 2016 compared to Q3 2015 and a lower weighted average hedge price.

- Total development capital expenditures decreased to $18.5 million in 2016 from $29.7 million in 2015. The 2016 activity was comprised mainly of the drilling and completion of joint development agreement wells, East Texas recompletions and workovers and capital costs related to CO_2 properties.

Commodity Derivative Contracts

We enter into oil and natural gas derivative contracts to help mitigate the risk of changing commodity prices. As of October 31, 2016, we had entered into derivative agreements to receive average NYMEX WTI crude oil prices and NYMEX Henry Hub, NWPL, SoCal and San Juan natural gas prices as summarized below.

WTI Crude Oil Swaps:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
October-December 2016	496,800	$54.91	$50.15 - $86.30
2017	182,500	$84.75	$84.75

WTI Crude Oil Costless Collars. At an average 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 $59.02, respectively.

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2017	2,190,000	$45.00	$59.02

WTI Crude Oil 3-Way Collars. At an 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:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
October-December 2016	115,000	$60.00	$85.00	$102.46
2017	72,400	$60.00	$85.00	$104.20

WTI Crude Oil Enhanced Swaps. At an 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:

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
October-December 2016	46,000	$57.00	$82.00	$91.70
2017	182,500	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

Midland-to-Cushing WTI Crude Oil Differential Swaps:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
October-December 2016	736,000	$(1.60)	$(1.75) - $(1.50)
2017	2,190,000	$(0.30)	$(0.75) - $(0.05)

Natural Gas Swaps (Henry Hub):

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
October-December 2016	12,450,000	$3.00	$2.42 - $4.12
2017	27,600,000	$3.36	$3.29 - $3.39
2018	42,200,000	$3.25	$3.04 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

Natural Gas Costless Collars (Henry Hub). At an average Henry Hub market 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 (MMBtu)	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2017	14,600,000	$2.90	$3.44

Natural Gas 3-Way Collars (Henry Hub). 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:

Time Period	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
October-December 2016	1,395,000	$3.75	$4.25	$5.08
2017	5,040,000	$3.75	$4.25	$5.53

Natural Gas Basis Swaps (NWPL, SoCal and San Juan):

	October-December 2016		2017	
	Volumes (MMBtu)	Average Price per MMBtu	Volumes (MMBtu)	Average Price per MMBtu
NWPL	3,764,916	$(0.19)	7,300,000	$(0.16)
SoCal	—	$—	2,500,250	$0.11
San Juan	628,360	$(0.16)	2,500,250	$(0.10)

Location and quality differentials attributable to our properties are not reflected in the above prices. The agreements provide for monthly settlement based on the difference between the agreement fixed price and the actual reference oil and natural gas index prices.

Quarterly Report on Form 10-Q

Financial results contained herein are preliminary and subject to the final, unaudited financial statements and related footnotes included in Legacy's Form 10-Q which will be filed on or about November 2, 2016.

Conference Call

As announced on October 25, 2016, Legacy will host an investor conference call to discuss Legacy's results on Thursday, November 3, 2016 at 9:00 a.m. (Central Time). Those wishing to participate in the conference call should dial 877-266-0479. A replay of the call will be available through Thursday, November 10, 2016, by dialing 855-859-2056 or 404-537-3406 and entering replay code 98590760. Those wishing to listen to the live or archived web cast via the Internet should go to the Investor Relations tab of our website at www.LegacyLP.com. Following our prepared remarks, we will be pleased to answer questions from securities analysts and institutional portfolio managers and analysts; the complete call is open to all other interested parties on a listen-only basis.

Additional Information for Holders of Legacy Units

Although Legacy has suspended distributions to both the 8% Series A and Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units"), such distributions continue to accrue. Pursuant to the terms of Legacy's partnership agreement, Legacy is required to pay or set aside for payment all accrued but unpaid distributions with respect to the Preferred Units prior to or contemporaneously with making any distribution with respect to Legacy's units. Accruals of distributions on the Preferred Units are treated for tax purposes as guaranteed payments for the use of capital that will generally be taxable to the holders of such Preferred Units as ordinary income even in the absence of contemporaneous distributions.

In addition, Legacy's unitholders, just like unitholders of other master limited partnerships, are allocated taxable income irrespective of cash distributions paid. Because Legacy's unitholders are treated as partners that are allocated a share of Legacy's taxable income irrespective of the amount of cash, if any, distributed by Legacy, unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of Legacy's taxable income, including its taxable income associated with cancellation of debt ("COD income") or a disposition of property by Legacy, even if they receive no cash distributions from Legacy. As of January 21, 2016, Legacy has suspended all cash distributions to unitholders and holders of the Preferred Units.

Legacy may engage in transactions to de-lever the Partnership and manage its liquidity that may result in the allocation of income and gain to its unitholders without a corresponding cash distribution. For example, during the nine month period ended September 30, 2016, Legacy closed 23 divestitures generating net proceeds of $95.5 million, and Legacy may sell additional assets and use the proceeds to repay existing debt or fund capital expenditure, in which case Legacy's 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, Legacy may pursue other opportunities to reduce its existing debt, such as debt exchanges, debt repurchases, or modifications that would result in COD income being allocated to its unitholders as ordinary taxable income. The ultimate effect of any income allocations will depend on the unitholder's individual tax position with respect to its units, 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.

Additionally, if Legacy's unitholders, just like unitholders of other master limited partnerships, 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 Legacy's 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 Legacy's unitholders due to the potential recapture items, including depreciation, depletion and intangible drilling.

About Legacy Reserves LP

Legacy Reserves LP is a master limited partnership headquartered in Midland, Texas, focused on the acquisition and development of oil and natural gas properties primarily located in the Permian Basin, East Texas, Rocky Mountain and Mid-Continent regions of the United States. Additional information is available at www.LegacyLP.com.

Cautionary Statement Relevant to Forward-Looking Information

This press release contains forward-looking statements relating to our operations that are based on management's current expectations, estimates and projections about its operations. Words such as "anticipates," "expects," "intends," "plans," "targets," "projects," "believes," "seeks," "schedules," "estimated," and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: realized oil and natural gas prices; production volumes, lease operating expenses, general and administrative costs and finding and development costs; future operating results and the factors set forth under the heading "Risk Factors" in our annual and quarterly reports filed with the SEC. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this press release. Unless legally required, Legacy undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 38,751	$ 49,779	$ 110,343	$ 159,188
Natural gas liquids (NGL) sales	3,457	2,946	9,832	12,867
Natural gas sales	41,332	36,773	102,591	86,783
Total revenues	83,540	89,498	222,766	258,838
Expenses:				
Oil and natural gas production	43,121	48,446	137,705	142,886
Production and other taxes	3,986	4,834	9,949	13,038
General and administrative	9,231	16,246	29,658	35,506
Depletion, depreciation, amortization and accretion	36,068	45,041	110,695	122,306
Impairment of long-lived assets	4,618	98,054	20,065	307,455
(Gain) loss on disposal of assets	(8,447)	560	(49,289)	1,567
Total expenses	88,577	213,181	258,783	622,758
Operating loss	(5,037)	(123,683)	(36,017)	(363,920)
Other income (expense):				
Interest income	—	(55)	54	326
Interest expense	(17,080)	(23,351)	(62,558)	(58,903)
Gain on extinguishment of debt	—	—	150,802	—
Equity in income (loss) of equity method investees	7	(6)	(7)	97
Net gains (losses) on commodity derivatives	18,326	57,000	(2,311)	63,982
Other	(296)	19	(487)	723
Incomes (loss) before income taxes	(4,080)	(90,076)	49,476	(357,695)
Income tax (expense) benefit	(223)	(1)	(710)	290
Net income (loss)	$ (4,303)	$ (90,077)	$ 48,766	$ (357,405)
Distributions to Preferred unitholders	(4,750)	(4,750)	(13,458)	(14,250)
Net income (loss) attributable to unitholders	$ (9,053)	$ (94,827)	$ 35,308	$ (371,655)
Income (loss) per unit - basic and diluted	$ (0.13)	$ (1.38)	$ 0.50	$ (5.39)
Weighted average number of units used in computing net income (loss) per unit -				
Basic and diluted	72,056	68,945	70,370	68,921

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	September 30, 2016	December 31, 2015
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 2,030	$ 2,006
Accounts receivable, net:		
Oil and natural gas	38,138	33,944
Joint interest owners	21,669	25,378
Other	2	86
Fair value of derivatives	26,383	63,711
Prepaid expenses and other current assets	8,662	4,334
Total current assets	96,884	129,459
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	3,296,942	3,485,634
Unproved properties	13,412	13,424
Accumulated depletion, depreciation, amortization and impairment	(2,064,054)	(2,090,102)
	1,246,300	1,408,956
Other property and equipment, net of accumulated depreciation and amortization of $10,048 and $8,915, respectively	3,751	4,575
Operating rights, net of amortization of $5,265 and $4,953, respectively	1,752	2,064
Fair value of derivatives	33,250	56,373
Other assets	9,869	11,047
Investments in equity method investees	640	646
Total assets	$ 1,392,446	$ 1,613,120

LIABILITIES AND PARTNERS' DEFICIT

	September 30, 2016	December 31, 2015
Current liabilities:		
Accounts payable	$ 5,391	$ 13,581
Accrued oil and natural gas liabilities	53,590	50,573
Fair value of derivatives	1,892	2,019
Asset retirement obligation	3,496	3,496
Other	20,662	11,424
Total current liabilities	85,031	81,093
Long-term debt	1,157,490	1,427,614
Asset retirement obligation	266,173	282,909
Fair value of derivatives	2,059	—
Other long-term liabilities	643	1,181
Total liabilities	1,511,396	1,792,797
Commitments and contingencies		
Partners' equity		
Series A Preferred equity - 2,300,000 units issued and outstanding at September 30, 2016 and December 31, 2015	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at September 30, 2016 and December 31, 2015	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at September 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 September 30, 2016 and December 31, 2015, respectively	(379,098)	(439,811)
General partner's deficit (approximately 0.03%)	(119)	(133)
Total partners' deficit	(118,950)	(179,677)
Total liabilities and partners' deficit	$ 1,392,446	$ 1,613,120

Non-GAAP Financial Measures

This press release, the financial tables and other supplemental information include "Adjusted EBITDA" and "Distributable Cash Flow", both of which are non-generally accepted accounting principles ("non-GAAP") measures which may be used periodically by management when discussing our financial results with investors and analysts. The following presents a reconciliation of each of these non-GAAP financial measures to their nearest comparable generally accepted accounting principles ("GAAP") measure.

Adjusted EBITDA and Distributable Cash Flow are presented as management believes they provide additional information concerning the performance of our business and are used by investors and financial analysts to analyze and compare our current operating and financial performance relative to past performance and such performances relative to that of other publicly traded partnerships in the industry. Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of other publicly traded limited partnerships or limited liability companies because all companies may not calculate such measures in the same manner.

Distributable Cash Flow is one of the factors used by the board of directors of our general partner (the "Board") to help determine the amount of Available Cash as defined in our partnership agreement, that is to be distributed to our unitholders for such period. Under our partnership agreement, Available Cash is defined generally to mean, cash on hand at the end of each quarter, plus working capital borrowings made after the end of the quarter, less cash reserves determined by our general partner. The Board determines whether to increase, maintain or decrease the current level of distributions in accordance with the provisions of our partnership agreement based on a variety of factors, including without limitation, Distributable Cash Flow, cash reserves established in prior periods, reserves established for future periods, borrowing capacity for working capital, temporary, one-time or uncharacteristic historical results, and forecasts of future period results including the impact of pending acquisitions. Management and the Board consider the long-term view of expected results in determining the amount of its distributions. Certain factors impacting Adjusted EBITDA and Distributable Cash Flow may be viewed as temporary, one-time in nature, or being offset by reserves from past performance or near-term future performance. Financial results are also driven by various factors that do not typically occur evenly throughout the year that are difficult to predict, including rig availability, weather, well performance, the timing of drilling and completions and near-term commodity price changes. Consistent with practices common to publicly traded partnerships, the Board historically has not varied the distribution it declares based on such timing effects.

"Adjusted EBITDA" and "Distributable Cash Flow" should not be considered as alternatives to GAAP measures, such as net income, operating income, cash flow from operating activities, or any other GAAP measure of financial performance.

The following table presents a reconciliation of our consolidated net income (loss) to Adjusted EBITDA and Distributable Cash Flow:

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(In thousands)			
Net income (loss)	$ (4,303)	$ (90,077)	$ 48,766	$ (357,405)
Plus:				
Interest expense	17,080	23,351	62,558	58,903
Gain on extinguishment of debt	—	—	(150,802)	—
Income tax expense (benefit)	223	1	710	(290)
Depletion, depreciation, amortization and accretion	36,068	45,041	110,695	122,306
Impairment of long-lived assets	4,618	98,054	20,065	307,455
(Gain) loss on disposal of assets	(8,447)	560	(49,289)	1,567
Equity in (income) loss of equity method investees	(7)	6	7	(97)
Unit-based compensation expense	1,445	1,704	5,612	4,985
Minimum payments received in excess of overriding royalty interest earned(1)	423	386	1,225	1,130
Equity in EBITDA of equity method investee(2)	—	—	—	169
Net (gains) losses on commodity derivatives	(18,326)	(57,000)	2,311	(63,983)
Net cash settlements received on commodity derivatives	11,613	26,788	56,483	104,314
Transaction related expenses	296	6,502	1,087	8,175
Adjusted EBITDA	$ 40,683	$ 55,316	$ 109,428	$ 187,229
Less:				
Cash interest expense	17,454	18,632	54,181	52,624
Development capital expenditures(3)	6,866	7,881	18,542	29,663
Distributions on Series A and Series B preferred units	—	4,750	—	14,250
Distributable Cash Flow	$ 16,363	$ 24,053	$ 36,705	$ 90,692

(1) Minimum payments received in excess of overriding royalties earned under a contractual agreement expiring December 31, 2019. The remaining amount of the minimum payments is recognized in net income.

(2) Equity in EBITDA of equity method investee is defined as the equity method investee's net income or loss plus interest expense and depreciation. We divested our interest in this investee in May of 2015.

(3) Represents total capital expenditures for the development of oil and natural gas properties as presented on an accrual basis. For 2016, we intend to fund our total oil and natural gas development program from net cash provided by operating activities.

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