Legacy Reserves LP Announces Third Quarter 2017 Results, Extension of Second Lien Availability and Updated Financial Guidance

MIDLAND, Texas, November 1, 2017- (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced third quarter results for 2017 including the following highlights:

- Completed $3.3 million of acreage acquisitions expanding our future development opportunities including:
    - 24 horizontal Spraberry and Wolfcamp drilling locations in the Midland Basin, and
    - 9 horizontal San Andres drilling locations on the Central Basin Platform that leverage Legacy's existing infrastructure and have attractive offset development economics.

- Reduced commodity price risk by adding 5,300 Bbls/d of 2018 WTI crude oil swaps at average swap price of $52.97 per barrel.

- Increased oil production to a record 14,380 Bbls/d, a 25% increase relative to Q2 2017.

- Generated a net loss of $33.9 million.

- Generated Adjusted EBITDA of $58.8 million representing a 33% increase compared to Q2 2017.

- Reduced lease operating expenses, excluding ad valorem taxes, to $39.5 million representing a 6.5% decrease compared to Q2 2017 and yielding a record low LOE/BOE of $9.36.

- Extended the availability of the remaining $95 million undrawn portion of the second lien term loan to October 25, 2018.

Paul T. Horne, Chairman of the Board, President and Chief Executive Officer of Legacy's general partner commented, "Our August 1st Acceleration Payment and revisions to our JDA meaningfully increased our interest in our operated horizontal Permian development program. We remain very pleased with the team's ability to efficiently develop this resource as we recently brought on 9 additional wells. As always, we continue to optimize well design and operational practices, and I'm proud of our vigilance with costs as evidenced by our record-low LOE per Boe. Our land and business development teams have once again enhanced our portfolio through smart, cost-effective bolt-on acquisitions. We expect such efforts will build long-term equity value as we identify and pursue additional drilling prospects in our core operating areas."

Dan Westcott, Executive Vice President and Chief Financial Officer of Legacy's general partner, commented, "During the quarter, our high-density horizontal Permian development schedule necessitated temporarily shutting in a higher-than-anticipated amount of offset well production and, consequently, our Q3 production fell short of expectations. We are pleased with the results of these smart-minded, long-term focused decisions to optimize asset value. Our revised 2017 financial guidance implies 2H 2017 oil production growth of 41% relative to 1H 2017. While we are just beginning our 2018 capital budget process, we currently anticipate spending development capital of $200 to $225 million based on continuing a two-rig Permian program under our JDA. The included preliminary 2018 financial guidance shows 47% growth in oil production and 43% growth in Adjusted EBITDA relative to 2017 estimates, to a midpoint of 20,100 Bbl/d and $305 million, respectively. This significant growth underlines our high-quality assets and operational strength. We continue to focus on growing Adjusted EBITDA and asset value which should meaningfully improve our credit metrics as the midpoint of our preliminary 2018 guidance implies a free cash flow neutral program that reduces total debt / pro forma Adjusted EBITDA by about one and one-half times relative to year-end 2017 estimates. As part of our Fall redetermination, our borrowing base was reduced $25 million to $575 million leaving us with current availability of $89 million. In addition, we're pleased to have extended our $95 million of second lien availability for another year, increasing our total liquidity and expanding our optionality as we explore strategies to further delever the balance sheet and position Legacy for long-term success."

Financial Guidance

The following table sets forth certain assumptions used by Legacy to estimate its anticipated results of operations for 2017 and 2018. These estimates do not include any future acquisitions of additional oil or natural gas properties. In addition, these estimates are based on, among other things, assumptions of capital expenditure levels, current indications of supply and demand for oil and natural gas and current operating and labor costs. The guidance set forth below does not constitute any form of guarantee, assurance or promise that the matters indicated will actually be achieved. The guidance below sets forth management's best estimate based on current and anticipated market conditions and other factors. While we believe that these estimates and assumptions are reasonable, they are inherently uncertain and are subject to, among other things, significant business, economic, regulatory, environmental and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate, as set forth under "Cautionary Statement Relevant to Forward-Looking Information."

	Q4 2017E Range			FY 2017E Range			Preliminary FY 2018E Range		
	($ in thousands unless otherwise noted)								
Production:									
Oil (Bbls/d)	17,100	-	17,700	13,637	-	13,789	18,800	-	21,400
Natural gas liquids (Bbls/d)	2,275	-	2,325	2,370	-	2,383	2,025	-	2,300
Natural gas (MMcf/d)	170.0	-	174.0	171.5	-	172.5	162.5	-	177.5
Total (Boe/d)	47,708	-	49,025	44,590	-	44,922	47,908	-	53,283
Lease operating expenses[1]	$ 43,300	-	$ 44,300	$ 174,306	-	$ 175,306	$ 170,000	-	$ 190,000
Capital expenditures	$ 40,000	-	$ 42,000	$ 181,476	-	$ 183,476	$ 200,000	-	$ 225,000
Adjusted EBITDA[2]	$ 68,000	-	$ 71,000	$ 211,259	-	$ 214,259	$ 280,000	-	$ 330,000

(1) Excludes ad valorem and production taxes.

(2) Adjusted EBITDA is a Non-GAAP financial measure. This measure does not include pro forma adjustments permitted under our credit agreements relating to acquired and divested oil or gas properties. A reconciliation of this measure to the nearest comparable GAAP measure is available on our website.

Note: Figures above assume NYMEX strip pricing at 10/1/2017 (2018 average oil $51.94 / $3.05 natural gas).

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 59,060	$ 38,751	$ 154,298	$ 110,343
Natural gas liquids (NGL) sales	6,720	3,457	16,691	9,832
Natural gas sales	41,035	41,332	128,220	102,591
Total revenue	$ 106,815	$ 83,540	$ 299,209	$ 222,766
Expenses:				
Oil and natural gas production, excluding ad valorem taxes	$ 39,515	$ 40,118	$ 131,005	$ 128,299
Ad valorem taxes	2,564	3,003	7,093	9,406
Total oil and natural gas production	$ 42,079	$ 43,121	$ 138,098	$ 137,705
Production and other taxes	$ 5,475	$ 3,986	$ 13,779	$ 9,949
General and administrative, excluding trans. related costs and LTIP	$ 8,418	$ 7,490	$ 24,087	$ 22,959
Transaction related costs	54	296	138	1,087
LTIP expense	1,551	1,445	4,931	5,612
Total general and administrative	$ 10,023	$ 9,231	$ 29,156	$ 29,658
Depletion, depreciation, amortization and accretion	$ 33,715	$ 36,068	$ 90,200	$ 110,695
Commodity derivative cash settlements:				
Oil derivative cash settlements received	$ 3,102	$ 8,089	$ 9,800	$ 30,434
Natural gas derivative cash settlements received	$ 3,870	$ 3,524	$ 7,979	$ 26,049
Production:				
Oil (MBbls)	1,323	962	3,404	3,070
Natural gas liquids (MGal)	11,375	9,742	27,542	27,646
Natural gas (MMcf)	15,771	16,572	46,967	50,581
Total (MBoe)	4,222	3,956	11,888	12,158
Average daily production (Boe/d)	45,891	43,000	43,546	44,372
Average sales price per unit (excluding derivative cash settlements):				
Oil price (per Bbl)	$ 44.64	$ 40.28	$ 45.33	$ 35.94
Natural gas liquids price (per Gal)	$ 0.59	$ 0.35	$ 0.61	$ 0.36
Natural gas price (per Mcf)	$ 2.60	$ 2.49	$ 2.73	$ 2.03
Combined (per Boe)	$ 25.30	$ 21.12	$ 25.17	$ 18.32
Average sales price per unit (including derivative cash settlements):				
Oil price (per Bbl)	$ 46.99	$ 48.69	$ 48.21	$ 45.86
Natural gas liquids price (per Gal)	$ 0.59	$ 0.35	$ 0.61	$ 0.36
Natural gas price (per Mcf)	$ 2.85	$ 2.71	$ 2.90	$ 2.54
Combined (per Boe)	$ 26.95	$ 24.05	$ 26.66	$ 22.97
Average WTI oil spot price (per Bbl)	$ 48.18	$ 44.85	$ 49.30	$ 41.35
Average Henry Hub natural gas index price (per MMbtu)	$ 2.95	$ 2.88	$ 3.01	$ 2.34
Average unit costs per Boe:				
Oil and natural gas production, excluding ad valorem taxes	$ 9.36	$ 10.14	$ 11.02	$ 10.55
Ad valorem taxes	$ 0.61	$ 0.76	$ 0.60	$ 0.77
Production and other taxes	$ 1.30	$ 1.01	$ 1.16	$ 0.82
General and administrative excluding trans. related costs and LTIP	$ 1.99	$ 1.89	$ 2.03	$ 1.89
Total general and administrative	$ 2.37	$ 2.33	$ 2.45	$ 2.44
Depletion, depreciation, amortization and accretion	$ 7.99	$ 9.12	$ 7.59	$ 9.10

Financial and Operating Results - Three-Month Period Ended September 30, 2017 Compared to Three-Month Period Ended September 30, 2016

- Production increased 7% to 45,891 Boe/d from 43,000 Boe/d primarily due to additional oil production from our drilling operations in Howard County, Texas and Lea County, New Mexico and production attributable to the additional working interests that reverted to us in connection with making an acceleration payment (the "Acceleration Payment") under our amended and restated joint development agreement with TSSP (the "JDA"). This was partially offset by natural production declines and individually immaterial divestitures completed in 2016 and 2017.

- Average realized price, excluding net cash settlements from commodity derivatives, increased 20% to $25.30 per Boe in 2017 from $21.12 per Boe in 2016 driven by the significant increase in commodity prices and increase in oil production as a percentage of total production. Average realized oil price increased 11% to $44.64 in 2017 from $40.28 in 2016 driven by an increase in the average WTI crude oil price of $3.33 per Bbl and improving regional differentials. Average realized natural gas price increased 4% to $2.60 per Mcf in 2017 from $2.49 per Mcf in 2016. This increase is primarily a result of the increase in average Henry Hub natural gas index price of $0.07 per Mcf and improved realized regional differentials. Finally, our average realized NGL price increased 69% to $0.59 per gallon in 2017 from $0.35 per gallon in 2016.

- Production expenses, excluding ad valorem taxes, decreased to $39.5 million in 2017 from $40.1 million in 2016, primarily due to cost containment efforts across all operating regions partially offset by increased well count related to our Permian horizontal drilling program and expenses associated with the additional working interests that reverted to us in connection with making the Acceleration Payment. On an average cost per Boe basis, production expenses excluding ad valorem taxes decreased 8% to $9.36 per Boe in 2017 from $10.14 per Boe in 2016.

- Non-cash impairment expense of $14.7 million in 2017 was driven by the decrease in natural gas futures prices. Impairment expense of $4.6 million in 2016 was driven by well performance and the further decline in oil and natural gas prices during the period.

- General and administrative expenses, excluding unit-based Long-Term Incentive Plan ("LTIP") compensation expense, increased to $8.5 million in 2017 from $7.8 million in 2016 due to general cost increases.

- Cash settlements received on our commodity derivatives during 2017 were $7.0 million compared to $11.6 million in 2016. The decline in cash settlements received is a result of the combination of higher commodity prices and reduced nominal volumes hedges in Q3 2017 compared to Q3 2016 as well as lower contracted hedge prices.

- Total development capital expenditures increased to $93.2 million in 2017 from $6.9 million in 2016. The 2017 activity was comprised mainly of the drilling and completion of JDA wells. After the Acceleration Payment, we became responsible for 85% of the parties' combined interests of all remaining Tranche 1 capital costs to be paid regardless of when such costs were incurred, resulting in a larger increase in capital expenditures.

Financial and Operating Results - Nine-Month Period Ended September 30, 2017 Compared to Nine-Month Period Ended September 30, 2016

- Production decreased 2% to 43,546 Boe/d from 44,372 Boe/d primarily due to natural production declines and individually immaterial divestitures partially offset by growth from our development activity and additional working interests that reverted to us in connection with making the Acceleration Payment.

- Average realized price, excluding net cash settlements from commodity derivatives, increased 37% to $25.17 per Boe in 2017 from $18.32 per Boe in 2016 driven primarily by the significant increase in commodity prices. Average realized oil price increased 26% to $45.33 in 2017 from $35.94 in 2016 driven by an increase in the average WTI crude oil price of $7.95 per Bbl. Average realized natural gas price increased 35% to $2.73 per Mcf in 2017 from $2.03 per Mcf in 2016. This increase is a result of the increase in the average Henry Hub natural gas index price of approximately $0.67 per Mcf partially offset by worsening realized regional differentials. Finally, our average realized NGL price increased 70% to $0.61 per gallon in 2017 from $0.36 per gallon in 2016.

- Production expenses, excluding ad valorem taxes, increased 2% to $131.0 million in 2017 from $128.3 million in 2016. On an average cost per Boe basis, production expenses increased 4% to $11.02 per Boe in 2017 from $10.55 per Boe in 2016. The increased expenses were primarily due to higher workover and repair activity in Q1 2017 across all operating regions and expenses associated with the additional working interests that reverted to us in connection with making the Acceleration Payment.

- Non-cash impairment expense totaled $24.5 million in 2017 driven by the continued decline in commodities futures prices and increased expenses. Impairment expense totaled $20.1 million in 2016 due to well performance and the decline in commodities futures prices in 2016.

- General and administrative expenses, excluding unit-based LTIP compensation expense totaled $24.2 million in 2017 compared to $24.0 million in 2016.

- Cash settlements received on our commodity derivatives during 2017 were $17.8 million compared to $56.5 million in 2016. The decline in cash settlements received is a result of the combination of reduced nominal volumes hedges in 2017 compared to 2016 as well as lower average hedge prices and higher commodity prices.

- Total development capital expenditures increased to $141.5 million in 2017 from $18.5 million in 2016. The 2017 activity was comprised mainly of the drilling and completion of JDA wells and recompletions and workovers across all of our operating regions.

Commodity Derivative Contracts

We enter into oil and natural gas derivative contracts to help mitigate the risk of changing commodity prices. As of October 30, 2017, 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 2017	46,000	$84.75	$84.75
2018	2,664,500	$53.54	$51.20 - $58.04

WTI Crude Oil Costless Collars. At an annual WTI market price of $40.00, $50.00 and $65.00, the summary positions below would result in a net price of $45.00, $50.00 and $59.02, respectively for 2017 and $47.06, $50.00 and $60.29, respectively for 2018.

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Call Price per Bbl
October-December 2017	552,000	$45.00	$59.02
2018	1,551,250	$47.06	$60.29

WTI Crude Oil Enhanced Swaps. At an annual average WTI market price of $40.00, $50.00 and $65.00, the summary positions below would result in a net price of $65.85, $65.85 and $73.85, respectively for 2017 and $65.50, $65.50 and $73.50, respectively for 2018.

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
October-December 2017	46,000	$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 2017	552,000	$(0.30)	$(0.75) - $(0.05)
2018	4,015,000	$(1.13)	$(1.25) - $(0.80)
2019	730,000	$(1.15)	$(1.15)

Natural Gas Swaps (Henry Hub):

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
October-December 2017	6,900,000	$3.36	$3.29 - $3.39
2018	36,200,000	$3.23	$3.04 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

Natural Gas Costless Collars (Henry Hub). 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 (MMBtu)	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
October-December 2017	3,680,000	$2.90	$3.44

Natural Gas 3-Way Collars (Henry Hub). At an annual average Henry Hub market price of $2.50, $3.00 and $3.50, the summary position below would result in a net price of $3.00, $3.50 and $4.00, respectively for 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 2017	1,260,000	$3.75	$4.25	$5.53

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

	October-December 2017	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	1,840,000	$(0.16)
SoCal	630,200	$0.11
San Juan	630,200	$(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 1, 2017.

Conference Call

As announced on October 18, 2017, Legacy will host an investor conference call to discuss Legacy's results on Thursday, November 2, 2017 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 9, 2017, by dialing 855-859-2056 or 404-537-3406 and entering replay code 99408146. Those wishing to listen to the live or archived webcast 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.

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.

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 year ended December 31, 2016, Legacy closed 26 divestitures generating net proceeds of $97.4 million, and Legacy may sell additional assets and use the proceeds to repay existing debt or fund capital expenditures, 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 that holder's 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.

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,	
	2017	2016	2017	2016
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 59,060	$ 38,751	$ 154,298	$ 110,343
Natural gas liquids (NGL) sales	6,720	3,457	16,691	9,832
Natural gas sales	41,035	41,332	128,220	102,591
Total revenues	106,815	83,540	299,209	222,766
Expenses:				
Oil and natural gas production	42,079	43,121	138,098	137,705
Production and other taxes	5,475	3,986	13,779	9,949
General and administrative	10,023	9,231	29,156	29,658
Depletion, depreciation, amortization and accretion	33,715	36,068	90,200	110,695
Impairment of long-lived assets	14,665	4,618	24,548	20,065
(Gain) loss on disposal of assets	(2,034)	(8,447)	3,491	(49,289)
Total expenses	103,923	88,577	299,272	258,783
Operating income (loss)	2,892	(5,037)	(63)	(36,017)
Other income (expense):				
Interest income	35	—	44	54
Interest expense	(23,621)	(17,080)	(64,368)	(62,558)
Gain on extinguishment of debt	—	—	—	150,802
Equity in income (loss) of equity method investees	—	7	12	(7)
Net gains (losses) on commodity derivatives	(13,309)	18,326	35,876	(2,311)
Other	403	(296)	765	(487)
Income (loss) before income taxes	(33,600)	(4,080)	(27,734)	49,476
Income tax expense	(266)	(223)	(837)	(710)
Net income (loss)	$ (33,866)	$ (4,303)	$ (28,571)	$ 48,766
Distributions to Preferred unitholders	(4,750)	(4,750)	(14,250)	(13,458)
Net income (loss) attributable to unitholders	$ (38,616)	$ (9,053)	$ (42,821)	$ 35,308
Income (loss) per unit - basic and diluted	$ (0.53)	$ (0.13)	$ (0.59)	$ 0.50
Weighted average number of units used in computing net income (loss) per unit -				
Basic and diluted	72,562	72,056	72,341	70,370

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	September 30, 2017	December 31, 2016
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 7,548	$ 2,555
Accounts receivable, net:		
Oil and natural gas	46,695	43,192
Joint interest owners	19,457	23,414
Other	—	2
Fair value of derivatives	15,566	6,162
Prepaid expenses and other current assets	8,425	7,447
Total current assets	97,691	82,772
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	3,495,569	3,305,856
Unproved properties	25,463	13,448
Accumulated depletion, depreciation, amortization and impairment	(2,159,559)	(2,137,395)
	1,361,473	1,181,909
Other property and equipment, net of accumulated depreciation and amortization of $11,174 and $10,412, respectively	3,142	3,423
Operating rights, net of amortization of $5,666 and $5,369, respectively	1,350	1,648
Fair value of derivatives	16,972	20,553
Other assets	8,704	8,874
Investments in equity method investees	658	647
Total assets	$ 1,489,990	$ 1,299,826

LIABILITIES AND PARTNERS' DEFICIT

	September 30, 2017	December 31, 2016
Current liabilities:		
Accounts payable	$ 5,611	$ 9,092
Accrued oil and natural gas liabilities	98,104	53,248
Fair value of derivatives	646	9,743
Asset retirement obligation	2,980	2,980
Other	29,643	11,546
Total current liabilities	136,984	86,609
Long-term debt	1,330,801	1,161,394
Asset retirement obligation	268,783	269,168
Fair value of derivatives	—	4,091
Other long-term liabilities	643	643
Total liabilities	1,737,211	1,521,905
Commitments and contingencies		
Partners' deficit		
Series A Preferred equity - 2,300,000 units issued and outstanding at September 30, 2017 and December 31, 2016	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at September 30, 2017 and December 31, 2016	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at September 30, 2017 and December 31, 2016	30,814	30,814
Limited partners' deficit - 72,594,620 and 72,056,097 units issued and outstanding at September 30, 2017 and December 31, 2016, respectively	(507,335)	(482,200)
General partner's deficit (approximately 0.03%)	(153)	(146)
Total partners' deficit	(247,221)	(222,079)
Total liabilities and partners' deficit	$ 1,489,990	$ 1,299,826

Non-GAAP Financial Measures

"Adjusted EBITDA" is a non-generally accepted accounting principles ("non-GAAP") measure which may be used periodically by management when discussing our financial results with investors and analysts. The following presents a reconciliation of this non-GAAP financial measure to its nearest comparable generally accepted accounting principles ("GAAP") measure.

Adjusted EBITDA is presented as management believes it provides additional information concerning the performance of our business and is 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 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.

Certain factors impacting Adjusted EBITDA 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.

"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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
	(In thousands)			
Net income (loss)	$ (33,866)	$ (4,303)	$ (28,571)	$ 48,766
Plus:				
Interest expense	23,621	17,080	64,368	62,558
Gain on extinguishment of debt	—	—	—	(150,802)
Income tax expense	266	223	837	710
Depletion, depreciation, amortization and accretion	33,715	36,068	90,200	110,695
Impairment of long-lived assets	14,665	4,618	24,548	20,065
(Gain) loss on disposal of assets	(2,034)	(8,447)	3,491	(49,289)
Equity in (income) loss of equity method investees	—	(7)	(12)	7
Unit-based compensation expense	1,551	1,445	4,931	5,612
Minimum payments received in excess of overriding royalty interest earned(1)	512	423	1,427	1,225
Net (gains) losses on commodity derivatives	13,309	(18,326)	(35,876)	2,311
Net cash settlements received on commodity derivatives	6,972	11,613	17,779	56,483
Transaction related expenses	54	296	138	1,087
Adjusted EBITDA	$ 58,765	$ 40,683	$ 143,260	$ 109,428

(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.

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