Legacy Reserves LP Announces First Quarter 2017 Results and Provides Operational and Financial Update

MIDLAND, Texas, May 3, 2017- (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced first quarter results for 2017 including the following Q1 highlights:

- Deployed $23.7 million of development capital as follows:
    - $16.7 million on drilling 8 and completing 7 Permian horizontal wells in Howard County, TX and Lea County, NM under our Joint Development Agreement ("JDA")
    - $4.1 million on workovers across all operating regions
    - $1.5 million on infrastructure and CO_2
    - $1.4 million on non-operated properties

- Spent approximately $4.8 million acquiring additional Midland Basin leasehold adding 24 gross potential horizontal drilling locations.

- Generated net income of $16.4 million.

- Obtained the reaffirmation of a $600 million borrowing base under our revolving credit facility.

Paul T. Horne, Chairman, President and Chief Executive Officer, commented, “Our company started the year off well as we grew oil production by 9% relative to Q4 of last year, driven by our recent Permian horizontal drilling efforts. While LOE was up 19% relative to Q4, the primary driver was an increase in returning wells to production and workovers that are now economic in an improved commodity price environment. This proactive well work in the Permian Basin and East Texas served to further reduce oil and gas declines for our portfolio of shallow-decline properties, the base from which we intend to grow the business in 2017 and beyond.”

Dan Westcott, Executive Vice President and Chief Financial Officer, commented, “We are extremely proud of our team’s execution of the Permian horizontal development that we outlined at year-end. Our front-end weighted capital program is concentrated on high-return projects and we anticipate continued oil production growth throughout the year. During the quarter, we again improved our credit profile as we reduced our borrowings outstanding by $15 million and maintained our $600 million borrowing base. We remain focused on the prudent management of our shallow-decline properties and the efficient development of our horizontal Permian potential.”

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended March 31,	
	2017	2016
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$ 49,142	$ 30,320
Natural gas liquids (NGL) sales	5,050	2,453
Natural gas sales	45,355	33,086
Total revenue	$ 99,547	$ 65,859
Expenses:		
Oil and natural gas production, excluding ad valorem taxes	$ 49,228	$ 46,661
Ad valorem taxes	$ 1,989	$ 3,362
Total oil and natural gas production	$ 51,217	$ 50,023
Production and other taxes	$ 4,159	$ 2,573
General and administrative, excluding trans. related costs and LTIP	$ 8,623	$ 7,692
Transaction related costs	$ 32	$ 77
LTIP expense	$ 1,897	$ 1,665
Total general and administrative	$ 10,552	$ 9,434
Depletion, depreciation, amortization and accretion	$ 28,796	$ 36,959
Commodity derivative cash settlements:		
Oil derivative cash settlements received	$ 3,139	$ 12,585
Natural gas derivative cash settlements received	$ 1,097	$ 10,192
Production:		
Oil (MBbls)	1,037	1,069
Natural gas liquids (MGal)	7,653	8,241
Natural gas (MMcf)	15,592	17,266
Total (MBoe)	3,818	4,143
Average daily production (Boe/d)	42,422	45,527
Average sales price per unit (excluding derivative cash settlements):		
Oil price (per Bbl)	$ 47.39	$ 28.36
Natural gas liquids price (per Gal)	$ 0.66	$ 0.30
Natural gas price (per Mcf)	$ 2.91	$ 1.92
Combined (per Boe)	$ 26.07	$ 15.90
Average sales price per unit (including derivative cash settlements):		
Oil price (per Bbl)	$ 50.42	$ 40.14
Natural gas liquids price (per Gal)	$ 0.66	$ 0.30
Natural gas price (per Mcf)	$ 2.98	$ 2.51
Combined (per Boe)	$ 27.18	$ 21.39
Average WTI oil spot price (per Bbl)	$ 51.62	$ 33.35
Average Henry Hub natural gas index price (per MMbtu)	$ 3.02	$ 1.99
Average unit costs per Boe:		
Oil and natural gas production, excluding ad valorem taxes	$ 12.89	$ 11.26
Ad valorem taxes	$ 0.52	$ 0.81
Production and other taxes	$ 1.09	$ 0.62
General and administrative excluding trans. related costs and LTIP	$ 2.26	$ 1.86
Total general and administrative	$ 2.76	$ 2.28
Depletion, depreciation, amortization and accretion	$ 7.54	$ 8.92

Financial and Operating Results - Three-Month Period Ended March 31, 2017 Compared to Three-Month Period Ended March 31, 2016

- Production decreased 7% to 42,422 Boe/d from 45,527 Boe/d primarily due to natural production declines and immaterial divestitures completed in 2016. This decline was partially offset by additional production from our drilling operations in Howard County, Texas and Lea County, New Mexico.

- Average realized price, excluding net cash settlements from commodity derivatives, increased 64% to $26.07 per Boe in 2017 from $15.90 per Boe in 2016 driven by the significant increase in commodity prices. Average realized oil price increased 67% to $47.39 in 2017 from $28.36 in 2016 driven by an increase in the average West Texas Intermediate ("WTI") crude oil price of $18.27 per Bbl and improving regional differentials. Average realized natural gas price increased 52% to $2.91 per Mcf in 2017 from $1.92 per Mcf in 2016. This increase is primarily a result of the increase in average Henry Hub natural gas index price of $1.03 per Mcf. Finally, our average realized NGL price increased 120% to $0.66 per gallon in 2017 from $0.30 per gallon in 2016.

- Production expenses, excluding ad valorem taxes, increased 5% to $49.2 million in 2017 from $46.7 million in 2016, primarily due to increased workover and repair activity across all operating regions. On an average cost per Boe basis, production expenses excluding ad valorem taxes increased 14% to $12.89 per Boe in 2017 from $11.26 per Boe in 2016.

- General and administrative expenses, excluding unit-based Long-Term Incentive Plan compensation expense, increased to $8.7 million in 2017 from $7.8 million in 2016 due to settlement of amounts owed by joint interest owners and cash-based employee incentive compensation plans.

- Cash settlements received on our commodity derivatives during 2017 were $4.2 million compared to $22.8 million in 2016. The decline in cash settlements received is a result of the combination of reduced nominal volumes hedges in Q1 2017 compared to Q1 2016 as well as lower average hedge prices.

- Total development capital expenditures increased to $23.7 million in 2017 from $4.8 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 May 1, 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
April-December 2017	137,500	$84.75	$84.75
2018	730,000	$55.04	$55.00 - $55.15

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
April-December 2017	1,650,000	$45.00	$59.02
2018	1,551,250	$47.06	$60.29

WTI Crude Oil 3-Way Collars. At an annual average WTI market price of $40.00, $50.00 and $65.00, the summary position below would result in a net price of $65.00, $75.00 and $85.00, respectively.

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
April-June 2017	36,400	$60.00	$85.00	$104.20

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
April-December 2017	137,500	$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
April-December 2017	1,650,000	$(0.30)	$(0.75) - $(0.05)
2018	2,190,000	$(1.22)	$(1.25) - $(1.15)

Natural Gas Swaps (Henry Hub):

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
April-December 2017	20,700,000	$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 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
April-December 2017	11,000,000	$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
April-December 2017	3,780,000	$3.75	$4.25	$5.53

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

	April-December 2017	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	5,500,000	$(0.16)
SoCal	1,883,750	$0.11
San Juan	1,883,750	$(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 May 3, 2017.

Conference Call

As announced on April 19, 2017, Legacy will host an investor conference call to discuss Legacy's results on Thursday, May 4, 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, May 11, 2017, by dialing 855-859-2056 or 404-537-3406 and entering replay code 7772631. 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 March 31,	
	2017	2016
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$ 49,142	$ 30,320
Natural gas liquids (NGL) sales	5,050	2,453
Natural gas sales	45,355	33,086
Total revenues	99,547	65,859
Expenses:		
Oil and natural gas production	51,217	50,023
Production and other taxes	4,159	2,573
General and administrative	10,552	9,434
Depletion, depreciation, amortization and accretion	28,796	36,959
Impairment of long-lived assets	8,062	15,447
Gain on disposal of assets	(5,524)	(31,701)
Total expenses	97,262	82,735
Operating income (loss)	2,285	(16,876)
Other income (expense):		
Interest income	1	38
Interest expense	(20,133)	(25,176)
Gain on extinguishment of debt	—	130,804
Equity in income (loss) of equity method investees	11	(5)
Net gains on commodity derivatives	34,669	17,038
Other	(40)	(94)
Incomes before income taxes	16,793	105,729
Income tax expense	(421)	(400)
Net income	$ 16,372	$ 105,329
Distributions to Preferred unitholders	(4,750)	(3,958)
Net income attributable to unitholders	$ 11,622	$ 101,371
Income per unit - basic and diluted	$ 0.16	$ 1.47
Weighted average number of units used in computing net income per unit -		
Basic and diluted	72,103	68,964

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	March 31, 2017	December 31, 2016
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 1,860	$ 2,555
Accounts receivable, net:		
Oil and natural gas	45,890	43,192
Joint interest owners	21,116	23,414
Other	2	2
Fair value of derivatives	14,080	6,162
Prepaid expenses and other current assets	10,343	7,447
Total current assets	93,291	82,772
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	3,328,625	3,305,856
Unproved properties	18,518	13,448
Accumulated depletion, depreciation, amortization and impairment	(2,169,324)	(2,137,395)
	1,177,819	1,181,909
Other property and equipment, net of accumulated depreciation and amortization of $10,742 and $10,412, respectively	3,154	3,423
Operating rights, net of amortization of $5,468 and $5,369, respectively	1,548	1,648
Fair value of derivatives	31,631	20,553
Other assets	7,996	8,874
Investments in equity method investees	658	647
Total assets	$ 1,316,097	$ 1,299,826
LIABILITIES AND PARTNERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 4,193	$ 9,092
Accrued oil and natural gas liabilities	72,367	53,248
Fair value of derivatives	1,555	9,743
Asset retirement obligation	2,980	2,980
Other	20,003	11,546
Total current liabilities	101,098	86,609
Long-term debt	1,148,151	1,161,394
Asset retirement obligation	271,049	269,168
Fair value of derivatives	—	4,091
Other long-term liabilities	643	643
Total liabilities	1,520,941	1,521,905
Commitments and contingencies		
Partners' deficit		
Series A Preferred equity - 2,300,000 units issued and outstanding at March 31, 2017 and December 31, 2016	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at March 31, 2017 and December 31, 2016	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at March 31, 2017 and December 31, 2016	30,814	30,814
Limited partners' deficit - 72,151,013 and 72,056,097 units issued and outstanding at March 31, 2017 and December 31, 2016, respectively	(464,969)	(482,200)
General partner's deficit (approximately 0.03%)	(142)	(146)
Total partners' deficit	(204,844)	(222,079)
Total liabilities and partners' deficit	$ 1,316,097	$ 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 March 31,	
	2017	2016
	(In thousands)	
Net income	$ 16,372	$ 105,329
Plus:		
Interest expense	20,133	25,176
Gain on extinguishment of debt	—	(130,804)
Income tax expense	421	400
Depletion, depreciation, amortization and accretion	28,796	36,959
Impairment of long-lived assets	8,062	15,447
Gain on disposal of assets	(5,524)	(31,701)
Equity in (income) loss of equity method investees	(11)	5
Unit-based compensation expense	1,897	1,665
Minimum payments received in excess of overriding royalty interest earned(1)	445	802
Net gains on commodity derivatives	(34,669)	(17,038)
Net cash settlements received on commodity derivatives	4,236	22,777
Transaction related expenses	32	77
Adjusted EBITDA	$ 40,190	$ 29,094

(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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