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

MIDLAND, Texas, May 4, 2016- (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced first quarter results for 2016 including the following Q1 highlights:

- Increased production to 45,527 Boe/d
- Reduced lease operating expenses, excluding ad valorem taxes, of $46.7 million representing a nearly 4% decrease compared to Q4 2015
- Closed $68.5 million of asset sales, above our previously-announced target of $50 million
- Reduced debt outstanding by $191.8 million including a $38.0 million reduction in borrowings under our credit facility and $153.8 million of senior notes
- Reported net income of $105.3 million, representing earnings per unit of $1.47 driven by a gain on extinguishment of debt of $130.8 million

Operational Update

During Q1 2016 we spent $4.8 million of our $37 million 2016 capital budget representing 13% of the annual total. Approximately 20% was spent on recompletions and workovers in our East Texas region. The vast 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 12 horizontal wells under the program: 5 in Lea County, NM, 1 in Southern Reagan County, TX and 6 in Howard County, TX. Based on current strip pricing, we anticipate that our 2016 capital expenditures will be less than our initial $37 million capital budget. We do not maintain any long-term drilling contracts and serve as operator of approximately 90% of our anticipated capital program. Accordingly, we maintain significant control of the capital program budget and may deviate materially from the figures above based on market conditions (or otherwise) with the overriding intent to deploy capital prudently.

2016 Asset Sales Update

During Q1 2016, we closed seven divestitures generating net proceeds of $68.5 million. Below are the summary statistics of such sales:

Transaction Statistics:

Total Sales Price	$	68,459,288
Transaction Count		7
County Count		12
Total Net Acreage		13,225
Midland Basin Net Acreage (1)		5,469
% of Year-End 2015 Midland Basin Acreage (1)		*28%*
Average Gross Midland Basin Tract Size (acres)		233
Q4 2015 Production (Boe/d)		521
Cash Flow (2)	$	1,902,194
Total Gross Well Count		129
YE 2015 PUDs		1
Multiple of Cash Flow		36.0x
$ / Net Midland Basin Acre (3)	$	11,789

(1) Excludes our and TSSP's combined interests in approximately 4,092 net acres in the Midland Basin committed to the parties' development agreement.

(2) Estimate based on last twelve months prior to closing each transaction.

(3) Calculated as sales price received attributable to Midland Basin acreage divided by Midland Basin acreage.

In April, we completed four additional divestments for approximately $5.4 million, which brings our year to date percent of year-end 2015 Midland Basin acreage divested to 35%. We are continuing to pursue a few other select opportunities with the aim to complete a total of $100 million of asset sales during the first half of 2016.

Capital Structure Update

Through May 4, 2016, we have utilized a portion of the proceeds from asset sales to repurchase a total of $169.4 million of our senior notes in the open market. Our debt balances as of each of the respective dates are as follows:

	12/31/2015	3/31/2016	5/4/2016
	(In thousands)		
Credit Facility due 2019	$ 608,000	$ 570,000	$ 560,000
8% Senior Notes (1)	300,000	255,570	247,989
6.625% Senior Notes (1)	550,000	440,661	432,656
Total Debt Outstanding (1)	$ 1,458,000	$ 1,266,231	$ 1,240,645

(1) Excludes unamortized discount on Senior Notes.

On May 4, 2016, as a result of the scheduled spring redetermination process, our borrowing base under our revolving credit facility was redetermined to $630 million, down from $725 million as set in February. With outstanding borrowings of $560 million and $1.4 million of outstanding letters of credit, we currently have $68.6 million of availability.

Near-Term Outlook and Commentary

Paul T. Horne, President and Chief Executive Officer of Legacy's general partner commented, "Q1 represented our lowest realized pricing in our company history at $15.90 per Boe, or 34% and 71% lower than our 2015 and 2014 realized pricing on a per Boe basis, respectively. Despite this difficult challenge, our team continues to make meaningful operational improvements. LOE was down 4% from last quarter and down 19% on a comparable basis to Q1 2015 while G&A excluding LTIP and transaction related expenses was down 10% relative to last quarter. We remain incredibly disciplined with our capital spending, as during the quarter we only spent 13% of our previously announced annual budget, and now expect our capital expenditures to be lower for 2016. We are pleased with our initial results on our East Texas recompletion efforts and anticipate dedicating more capital to this effort. We are very pleased with our results to date under our horizontal Permian development program with TSSP, having beat our estimated drilling and completion costs by 19% driven by a 39% improvement in estimated drilling days while achieving very encouraging early production rates. Despite funding only 5% of the development capital net to our combined interests under this program, we generated 567 Boe/d of net production in the quarter. We are currently evaluating the resumption of the development program which could potentially occur in early Q3 2016."

"The recent rise in commodity prices has certainly been helpful to Legacy and the energy industry as a whole. However, given the gravity of the price depression relative to prior years, we are still operating in a highly challenging environment. Our focus for at least the remainder of the year will be to continue to maintain liquidity and reduce our debt outstanding and therefore we have no near-term plans to resume our distributions on either our preferred units or common units. As always, we will continue to closely watch the market and respond with business objectives that match accordingly."

Dan Westcott, Executive Vice President and Chief Financial Officer of Legacy's general partner commented, "We were able to make significant strides on improving our balance sheet during the quarter. The approximately $69 million of asset sales closed in Q1 have generated liquidity, reduced future plugging obligations, and improved our leverage statistics. Since the beginning of the year, we have used $21.5 million to repurchase $169.4 million of our senior notes, reflecting a projected cash interest savings of $11.9 million per year. In total, we have reduced our debt outstanding by $217.4 million since year-end. Our recently redetermined borrowing base of $630 million certainly narrows our liquidity and, given our earlier credit agreement amendment, prohibits any cash distributions on our preferred units and common units given our Total Debt / EBITDA currently exceeds 4.0x, and prohibits Senior Notes repurchases given we no longer meet the required minimum liquidity levels. However, in the final three quarters of the year, we currently project to generate $15-$20 million of free cash flow (excluding asset sales) from approximately 44.2 mboe/d of production, with differentials and lifting costs consistent with prior periods, and believe our current liquidity position is sustainable to run the business for the foreseeable future. We recognize that we have additional levers available to us, whether those are further asset sales, financings or otherwise and will pull such levers if needed based upon the financial and commodity markets presented. Our goals remain to continue to improve our balance sheet and position Legacy for success."

Ongoing Proxy Process

We are currently seeking the vote of all unitholders through our 2016 proxy process. Our proxy can be found at: http://ir.legacylp.com/proxy.cfm. If you have lost your voting instructions or if you have questions about the voting process, please do not hesitate to contact our proxy solicitor, Morrow & Co., toll free at 800-662-5200. Every vote is important and we strongly encourage you to vote your units.

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$ 30,320	$ 50,296
Natural gas liquids sales	2,453	4,192
Natural gas sales	33,086	27,051
Total revenue	$ 65,859	$ 81,539
Expenses:		
Oil and natural gas production, excluding ad valorem taxes	$ 46,661	$ 45,944
Ad valorem taxes	$ 3,362	$ 3,276
Total oil and natural gas production	$ 50,023	$ 49,220
Production and other taxes	$ 2,573	$ 4,218
General and administrative, excluding transaction related costs and LTIP	$ 7,692	$ 7,756
Transaction related costs	$ 77	$ 25
LTIP expense	$ 1,665	$ 1,088
Total general and administrative	$ 9,434	$ 8,869
Depletion, depreciation, amortization and accretion	$ 36,959	$ 41,068
Commodity derivative cash settlements:		
Oil derivative cash settlements received	$ 12,585	$ 32,200
Natural gas derivative cash settlements received	$ 10,192	$ 8,137
Production:		
Oil (MBbls)	1,069	1,200
Natural gas liquids (MGal)	8,241	9,686
Natural gas (MMcf)	17,266	9,658
Total (MBoe)	4,143	3,040
Average daily production (Boe/d)	45,527	33,778
Average sales price per unit (excluding derivative cash settlements):		
Oil price (per Bbl)	$ 28.36	$ 41.91
Natural gas liquids price (per Gal)	$ 0.30	$ 0.43
Natural gas price (per Mcf)	$ 1.92	$ 2.80
Combined (per Boe)	$ 15.90	$ 26.82
Average sales price per unit (including derivative cash settlements):		
Oil price (per Bbl)	$ 40.14	$ 68.75
Natural gas liquids price (per Gal)	$ 0.30	$ 0.43
Natural gas price (per Mcf)	$ 2.51	$ 3.64
Combined (per Boe)	$ 21.39	$ 40.09
Average WTI oil spot price (per Bbl)	$ 33.35	$ 48.49
Average Henry Hub natural gas index price (per Mcf)	$ 1.99	$ 2.90
Average unit costs per Boe:		
Oil and natural gas production, excluding ad valorem taxes	$ 11.26	$ 15.11
Ad valorem taxes	$ 0.81	$ 1.08
Production and other taxes	$ 0.62	$ 1.39
General and administrative excluding transaction related costs and LTIP	$ 1.86	$ 2.55
Total general and administrative	$ 2.28	$ 2.92
Depletion, depreciation, amortization and accretion	$ 8.92	$ 13.51

Financial and Operating Results - Three-Month Period Ended March 31, 2016 Compared to Three-Month Period Ended March 31, 2015

- Production increased 35% to 45,527 Boe/d from 33,778 Boe/d primarily due to our 2015 acquisitions including our East Texas acquisitions from WGR Operating LP and Anadarko E&P Onshore LLC ("Anadarko Acquisitions").

- Average realized price, excluding net cash settlements from commodity derivatives, decreased 41% to $15.90 per Boe in 2016 from $26.82 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 32% to $28.36 in 2016 from $41.91 in 2015 driven by a decrease in the average West Texas Intermediate ("WTI") crude oil price of $15.14 per Bbl partially offset by an improvement in realized regional differentials. Average realized natural gas price decreased 31% to $1.92 per Mcf in 2016 from $2.80 per Mcf in 2015. This decrease is a result of the decrease in the average Henry Hub natural gas index price of $0.91 per Mcf. Finally, our average realized NGL price decreased 30% to $0.30 per gallon in 2016 from $0.43 per gallon in 2015.

- Production expenses, excluding ad valorem taxes, increased 2% to $46.7 million in 2016 from $45.9 million in 2015, primarily due to production expenses related to our acquisition of East Texas properties ($9.2 million) partially offset by cost reduction efforts on our historical properties. On an average cost per Boe basis, production expenses excluding ad valorem taxes decreased 25% to $11.26 per Boe in 2016 from $15.11 per Boe in 2015, driven primarily by the inclusion of lower cost production from our acquired East Texas properties as well as cost reduction efforts in our historical properties.

- General and administrative expenses, excluding unit-based Long-Term Incentive Plan compensation expense totaled $7.8 million in 2016, flat to 2015, reflecting cost reduction efforts offsetting 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 $22.8 million compared to $40.3 million in 2015. While commodity prices were lower in 2016, the decline in cash settlements received is a result of the reduced nominal volumes hedges in Q1 2016 compared to Q1 2015.

- Total development capital expenditures decreased to $4.8 million in 2016 from $13.4 million in 2015. The 2016 activity was comprised mainly of the drilling and completion of joint development agreement wells and capital costs related to CO_2 properties.

- Non-cash impairment expense totaled $15.4 million due to the continued decline in oil and natural gas futures prices.

Commodity Derivative Contracts

We enter into oil and natural gas derivative contracts to help mitigate the risk of changing commodity prices. As of May 2, 2016, we had entered into derivative agreements to receive average NYMEX WTI crude oil prices and NYMEX Henry Hub, Waha, 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 2016	439,900	$67.93	$56.15 - $99.85
2017	182,500	$84.75	$84.75

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
April-December 2016	425,650	$62.46	$87.46	$105.34
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
April-December 2016	137,500	$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
April-December 2016	2,200,000	$(1.60)	$(1.50) - $(1.75)
2017	2,190,000	$(0.30)	$(0.05) - $(0.75)

Natural Gas Swaps (Henry Hub and Waha):

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
April-December 2016	21,746,400	$3.40	$3.29 - $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

Natural Gas 3-Way Collars (Henry Hub). At an annual average Henry Hub market price of $2.00, the summary positions below would result in a net price of $2.50 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
April-December 2016	4,185,000	$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)

	April-December 2016		2017	
	Volumes (MMBtu)	Average Price per MMBtu	Volumes (MMBtu)	Average Price per MMBtu
NWPL	11,253,825	$(0.19)	7,300,000	$(0.16)
SoCal	—	$—	2,500,250	$0.11
San Juan	1,878,250	$(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 May 4, 2016.

Conference Call

As announced on April 20, 2016, Legacy will host an investor conference call to discuss Legacy's results on Thursday, May 5, 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, May 12, 2016, by dialing 855-859-2056 or 404-537-3406 and entering replay code 86768701. 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 unitholders, just like unitholders of other master limited partnerships, are allocated taxable income irrespective of cash distributions paid. As partners in a partnership, unitholders are allocated a share of taxable income irrespective of the amount of cash, if any, distributed to the unitholders. Taxable income in a given period to a unitholder may include ordinary income from cancellation of our debt and capital gain upon disposition of properties and the tax allocation of taxable income may require the payment of United States federal income taxes and, in some cases, state and local income taxes by our unitholders. 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 income and gain to unitholders. For example, unitholders may be allocated taxable income and gain resulting from asset sales. Further, if Legacy engages in debt exchanges, debt repurchases, or modifications of our existing debt, these or similar transactions could result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to unitholders as taxable income. Unitholders may be allocated gain and income from asset sales and COD income and may owe income tax as a result of such allocations notwithstanding the fact that we have currently suspended cash distributions to unitholders. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. 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.

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 March 31,	
	2016	**2015**
	(In thousands, except per unit data)	
Revenues:		
Oil sales	$ 30,320	$ 50,296
Natural gas liquids (NGL) sales	2,453	4,192
Natural gas sales	33,086	27,051
Total revenues	65,859	81,539
Expenses:		
Oil and natural gas production	50,023	49,220
Production and other taxes	2,573	4,218
General and administrative	9,434	8,869
Depletion, depreciation, amortization and accretion	36,959	41,068
Impairment of long-lived assets	15,447	209,402
(Gain) loss on disposal of assets	(31,701)	1,941
Total expenses	82,735	314,718
Operating loss	(16,876)	(233,179)
Other income (expense):		
Interest income	38	206
Interest expense	(25,176)	(17,792)
Gain on extinguishment of debt	130,804	—
Equity in income (loss) of equity method investees	(5)	79
Net gains on commodity derivatives	17,038	20,480
Other	(94)	605
Incomes (loss) before income taxes	105,729	(229,601)
Income tax (expense) benefit	(400)	747
Net income (loss)	$ 105,329	$ (228,854)
Distributions to Preferred unitholders	(3,958)	(4,750)
Net income (loss) attributable to unitholders	$ 101,371	$ (233,604)
Income (loss) per unit - basic and diluted	$ 1.47	$ (3.39)
Weighted average number of units used in computing net income (loss) per unit -		
Basic and diluted	68,964	68,921

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	March 31, 2016	December 31, 2015
	(In thousands)	
Current assets:		
Cash	$ 5,269	$ 2,006
Accounts receivable, net:		
Oil and natural gas	29,086	33,944
Joint interest owners	26,796	25,378
Other	55	86
Fair value of derivatives	60,462	63,711
Prepaid expenses and other current assets	4,119	4,334
Total current assets	125,787	129,459
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	3,394,646	3,485,634
Unproved properties	13,425	13,424
Accumulated depletion, depreciation, amortization and impairment	(2,081,624)	(2,090,102)
	1,326,447	1,408,956
Other property and equipment, net of accumulated depreciation and amortization of $9,341 and $8,915, respectively	4,328	4,575
Operating rights, net of amortization of $5,057 and $4,953, respectively	1,960	2,064
Fair value of derivatives	52,226	56,373
Other assets	10,349	11,047
Investments in equity method investees	641	646
Total assets	$ 1,521,738	$ 1,613,120

LIABILITIES AND PARTNERS' DEFICIT

	March 31, 2016	December 31, 2015
Current liabilities:		
Accounts payable	$ 2,717	$ 13,581
Accrued oil and natural gas liabilities	43,561	50,573
Fair value of derivatives	2,291	2,019
Asset retirement obligation	3,496	3,496
Other	19,328	11,424
Total current liabilities	71,393	81,093
Long-term debt	1,238,073	1,427,614
Asset retirement obligation	281,429	282,909
Fair value of derivatives	2,404	—
Other long-term liabilities	1,181	1,181
Total liabilities	1,594,480	1,792,797
Commitments and contingencies		
Partners' equity		
Series A Preferred equity - 2,300,000 units issued and outstanding at March 31, 2016 and December 31, 2015	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at March 31, 2016 and December 31, 2015	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at March 31, 2016 and December 31, 2015	30,814	30,814
Limited partners' deficit - 68,972,841 and 68,949,961 units issued and outstanding at March 31, 2016 and December 31, 2015, respectively	(332,904)	(439,811)
General partner's deficit (approximately 0.03%)	(105)	(133)
Total partners' deficit	(72,742)	(179,677)
Total liabilities and partners' deficit	$ 1,521,738	$ 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 March 31,	
	2016	2015
	(In thousands)	
Net income (loss)	$ 105,329	$ (228,854)
Plus:		
Interest expense	25,176	17,792
Gain on extinguishment of debt	(130,804)	—
Income tax expense (benefit)	400	(747)
Depletion, depreciation, amortization and accretion	36,959	41,068
Impairment of long-lived assets	15,447	209,402
(Gain) loss on disposal of assets	(31,701)	1,941
Equity in income (loss) of equity method investees	5	(79)
Unit-based compensation expense	1,665	1,088
Minimum payments received in excess of overriding royalty interest earned(1)	802	367
Equity in EBITDA of equity method investee(2)	—	119
Net gains on commodity derivatives	(17,038)	(20,480)
Net cash settlements received on commodity derivatives	22,777	40,337
Transaction related expenses	77	25
Adjusted EBITDA	$ 29,094	$ 61,979
Less:		
Cash interest expense	19,228	17,042
Development capital expenditures(4)	4,801	13,366
Distributions on Series A and Series B preferred units	—	4,750
Distributable Cash Flow(3)	$ 5,065	$ 26,821

(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) Estimated maintenance capital expenditures are intended to represent the amount of capital required to fully offset declines in production, but do not target specific levels of proved reserves to be achieved. Estimated maintenance capital expenditures do not include the cost of new oil and natural gas reserve acquisitions, but rather the costs associated with converting proved developed non-producing, proved undeveloped and unproved reserves to proved developed producing reserves. These costs, which are incorporated in our annual capital budget as approved by the Board, include development drilling, recompletions, workovers and various other procedures to generate new or improve existing production on both operated and non-operated properties. Estimated maintenance capital expenditures are based on management's judgment of various factors including the long-term (generally 5-10 years) decline rate of our current production and the projected productivity of our total development capital expenditures. Actual production decline rates and capital efficiency may materially differ from our projections and such estimated maintenance capital expenditures may not maintain our production. Further, because estimated maintenance capital expenditures are not intended to target specific levels of reserves, if we do not acquire new proved or unproved reserves, our total reserves will decrease over time and we would be unable to sustain production at current levels, which could adversely affect our ability to pay a distribution at the current level or at all.

(4) 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.

CONTACT: Legacy Reserves LP
Dan Westcott
Executive Vice President and Chief Financial Officer
432-689-5200