SandRidge Energy, Inc. Updates Shareholders on Operations and Reports Financial Results for Third Quarter and First Nine Months of 2016

Oklahoma City, Oklahoma, November 8, 2016 – SandRidge Energy, Inc. (the "Company") (NYSE:SD) today announced financial and operational results for the quarter ended September 30, 2016.

Production in the third quarter was 4.6 MMBoe (49.6 MBoepd, 28% oil, 24% NGLs, 48% natural gas). One drilling rig was active in Oklahoma during the entire quarter, and one drilling rig was active for part of the quarter in the North Park Basin of Colorado, with well completion activity continuing into the fourth quarter. Capital expenditures were $52 million during the third quarter, bringing the total amount invested to $161 million through the third quarter of 2016, excluding acquisitions. Capital expenditure and operational guidance, noted below, has been updated for 2016 in addition to introducing 2017 capital expenditure guidance.

The Company reported a net loss of $404 million and net cash from operating activities of $75 million for the third quarter of 2016. When adjusting these reported amounts for items that are typically excluded by the investment community on the basis that such items affect the comparability of results, the Company's "adjusted net income" amounted to $25 million and "adjusted operating cash flow" totaled $32 million. Earnings before interest, income taxes, depreciation, depletion, and amortization, adjusted for certain other items, otherwise referred to as "adjusted EBITDA", for the third quarter was $65 million.

The Company has defined and reconciled adjusted net income, adjusted operating cash flow and adjusted EBITDA to the most directly comparable U.S. generally accepted accounting principles (GAAP) financial measures in supporting tables at the conclusion of this press release under the "Non-GAAP Financial Measures" beginning on page 15.

HIGHLIGHTS DURING AND SUBSEQUENT TO THE THIRD QUARTER INCLUDE:

- Relisted October 4th on NYSE with Ticker Symbol "SD"
- Continuing to Improve Capital Efficiency by Expanding Use of Multi and Extended Laterals[1]
- First Niobrara Extended Lateral and First Niobrara Test of an Additional Bench Drilled in Third Quarter, Completed and Flowing Back in Fourth Quarter
- North Park Niobrara Type Curve of 315 MBoe (86% Oil) EUR per Single Lateral
- Drilled Six Mid-Continent Laterals and Three North Park Basin Laterals in Third Quarter
- John Suter, SVP of Operations, Named Successor to Steve Turk who is Retiring as COO
- Third Quarter Production of 4.6 MMBoe (49.6 MBoepd, 28% Oil, 24% NGLs, 48% Natural Gas)
- Hedge Positions Added for Remainder of 2016 and in 2017 and 2018
- Updating 2016 Guidance and Introducing 2017 Capital Expenditure Guidance
- Total Liquidity of $536 Million Including Unrestricted Cash of $111 Million and $425 Million Available Under Senior Credit Facility as of October 31ST

1) A "lateral" is defined as a single one-mile section lateral whereas an "extended lateral" is defined as a two-mile lateral drilled across two sections, and a "multilateral" defined as two or more one-mile laterals drilled within a one-mile section.

COO STEVE TURK RETIRING, SANDRIDGE NAMES JOHN SUTER TO BECOME NEW COO

Effective December 31st, SandRidge Chief Operating Officer (COO) Steve Turk, 65, will retire, after having served in this leadership role since March 2015. John Suter, 56, now Senior Vice President of Operations, is being promoted to COO effective December 1st.

James Bennett, SandRidge CEO and President said, *"I want to thank Steve for his contributions to SandRidge during his tenure with the company. His extensive experience and informed decision making approach have provided consistent, steady leadership. Through our succession planning program, John's promotion to COO is something we have prepared for. John has taken on additional responsibilities across all of our operating areas in recent months and we expect the transition to be seamless."*

Mr. Suter joined SandRidge in April 2015 as Senior Vice President of Mid-Continent Operations, bringing with him extensive experience in the exploration and production sector, including most recently serving as Vice President of the Woodford business unit at American Energy Partners, LP from November 2013. From May 2010 to September 2013, he served as Vice President of Operations for Chesapeake Energy Corporation's Western Division, and before that, as Chesapeake's District Manager for the Barnett Shale and Southern Oklahoma assets. Before joining Chesapeake Energy, Mr. Suter served in various operational roles at Continental Resources, Inc., Cabot Oil & Gas Corporation and Petro-Lewis Corporation. He holds a Bachelor of Science degree in Petroleum Engineering from Texas Tech University.

MID-CONTINENT ASSETS IN OKLAHOMA AND KANSAS

- Third quarter production of 4.3 MMBoe (46.2 MBoepd, 24% oil, 25% NGLs, 51% natural gas)
- Drilled six laterals in the third quarter, bringing three laterals online
- 24 laterals drilled in the first nine months of 2016 with all Mid-Continent activity focused in Oklahoma
- First nine months of Mississippian drilling and completion costs averaged $1.9 million per lateral or $392 per completed foot, a ~26% reduction from all of 2015

MULTI AND EXTENDED LATERAL DEVELOPMENT

- 100% multi and extended lateral Mississippian drilling in 2016
- First North Park Niobrara extended lateral drilled
- 100% multi and extended lateral development planned in 2017 across both Niobrara and Mid-Continent assets

In 2013, SandRidge pioneered Mississippian multilateral technology, the technique of drilling two to four laterals from a single vertical wellbore. In late 2014, the Company's expanded development included extended laterals.

James Bennett, SandRidge President and CEO said, *"2016 has been a watershed year for SandRidge. The Company successfully restructured its balance sheet and currently has no cash interest burden and over $500 million of liquidity. We intend to conserve capital by reducing our 2016 capital expenditures from our original plan of $285 million to $220-240 million. Our multi and extended lateral program is more capital efficient every quarter. In the Mid-Continent, recent drilling and completion costs are below $2 million per lateral, with the completion of a dual two-mile extended lateral, the equivalent of four one-mile laterals in a single well, for $1.7 million per lateral. Recent drilling activity included our first Niobrara two-mile extended lateral, which demonstrates an attractive and repeatable combination of well costs and oil productivity. With an inventory of 1,300 proved and probable Niobrara laterals, we will resume Niobrara drilling in early 2017, further targeting additional productive Niobrara oil benches, tighter well spacing, and higher oil recoveries per well. We will continue using extended laterals in both of our plays."* Bennett went on to say, *"SandRidge expects to create value with competitive project IRRs from both the high-graded harvest of our Mid-Continent position and the portfolio diversification and potential long term oil growth of our emerging North Park Niobrara project and non-Mississippian targets in the Mid-Continent. Our larger goals are to increase oil weighting, reduce cost structure, and effectively manage a portfolio of competitive projects already in hand, while looking for additional opportunities to create resource value. We plan to achieve all of this while protecting our balance sheet, liquidity and minimizing cash flow outspend."*

Since inception of the multi and extended lateral program, the Company has drilled and completed 123 laterals using multilateral design and 50 laterals using extended lateral design. Most notably, SandRidge has uniquely applied the full section development multilateral design, where three or more laterals are drilled from a single wellbore. Both multi and extended laterals enable the Company to reduce drilling and completion costs and decrease operating expenses with common well site facilities and artificial lift equipment.

In the first nine months of 2016, SandRidge drilled and completed 17 laterals using multi and extended lateral designs in the Mid-Continent, including 100% Mississippian multi and extended lateral drilling. The previously reported Dettle 2408 1-29 20H, the first Mississippian dual extended lateral (two two-mile laterals), produced a 30-Day IP of 1,099 Boepd[2] (60% oil) and was drilled and completed for $6.8 million ($1.7 million per lateral).

Another example, the Earl 2414 1-11H 14H, a Chester extended lateral development well, was drilled for $4.3 million ($2.1 million per lateral), and produced a 30-Day IP of 560 Boepd (62% oil), matching expectations.

In the third quarter, the Richey 2407 1-21H, a Mississippian full section development well exceeded expectations with a 30-Day IP of 688 Boepd (66% oil) and was drilled and completed for a total of $5.3 million ($1.8 million per lateral).

Most recently, technical teams applied extended lateral drilling technology in the Company's North Park Basin asset by drilling and completing an extended lateral Niobrara well, the Castle 1-17H 20. Although early, initial rates are outperforming expectations. The Company plans to drill 100% multi and extended laterals in 2017 across both the North Park Basin and Mid-Continent assets.

Drilling rig in North Park on the Mutual Pad; 8 Niobrara laterals drilled from this pad in 2016.

NIOBRARA ASSET IN NORTH PARK BASIN, JACKSON COUNTY, COLORADO

- Third quarter production of 161 MBo (1.8 MBopd), an increase of 49% compared to the second quarter of 2016
- Averaged 3.3 MBopd the second half of October, including production from 11 Niobrara laterals drilled in 2016
- North Park Niobrara type curve of 315 MBoe (86% oil) per single lateral, supported by cumulative production from 14 laterals
- Drilled three laterals, completed four laterals, and brought three laterals online during the third quarter
- Drilled first two-mile extended lateral, the Castle 1-17H 20, for below $7 million, less than $3.5 million per lateral

SandRidge drilled 10 wells with 11 total laterals in the North Park Basin in 2016. The goal for the first five wells was to test initial drilling and completion techniques in the new basin and to prove production performance. The first five wells demonstrated consistent performance to establish the play. The Company's first Niobrara well, the Gregory 1-9H, exceeded type curve production expectations with a previously reported 30-Day IP of 550 Boepd (89% oil). The well has been online for over seven months, averaged 310 Boepd (84% oil) during the month of October, and has produced a total of ~75 MBo. In the second quarter, four additional laterals were drilled, completed, and brought online, with an average 30-Day IP of 460 Boepd. Averaging 91% oil, all four wells met or exceeded type curve performance estimates and indicated consistent performance in this area of development.

The goal for the second five well package was to test concepts related to various targeting, drilling and completion techniques. In the second quarter, a grouping of three laterals utilizing batch drilling and zipper frac completions improved cycle times. This lateral grouping, now under evaluation, used a

2) Calculated as the highest consecutive 30-Day average production rate during the early life of a well.

combination of crosslinked gel and slickwater frac systems. In the third quarter, three additional laterals were drilled. The first Niobrara extended lateral, the Castle 1-17H 20, and a lateral testing a shallower Niobrara bench, the Hebron 4-18H, were completed and brought online in the fourth quarter. Results for this five well pilot program are expected to be reported in the fourth quarter earnings release.

Drilling and completion cost reductions have been an ongoing focus throughout the year. Drilling efficiencies, such as mud and bit system advances, reduced overall drilling cycle times by 69% since the beginning of the program. Current spud to rig release cycle time is averaging 11 days. Additionally, further cost reductions from extended lateral drilling are expected to deliver wells costs of less than $7 million ($3.5 million per lateral) in 2017, supported by the highlighted recent extended lateral Castle 1-17H 20.

Construction of the Big Horn Central Tank Battery (CTB), which became operational in mid-October, has further advanced our field development. This facility will be the prototype for future full field development and supports all 11 laterals drilled in 2016. Future facility expansion will support production for up to 70 laterals at the Big Horn CTB, and the shared gathering concept will reduce the overall drilling footprint, wellsite facility costs and operating costs. Additionally, the Company completed a summer construction program building roads, pads and flow lines in advance of continued 2017 development. Aiding future well placement, a 64 square mile 3D seismic survey, planned for early 2017 will be merged with and is complementary to the existing 54 square mile 3D survey.

OTHER OPERATIONAL UPDATES

- During the third quarter, Permian Central Basin Platform properties produced 153 MBoe (1.7 MBoepd , 80% oil, 13% NGLs, 7% natural gas)

KEY FINANCIAL RESULTS

Third Quarter

- Adjusted EBITDA, net of Noncontrolling Interest, was $65 million for third quarter 2016 compared to $118 million in third quarter 2015
- Adjusted operating cash flow of $32 million for third quarter 2016 compared to $45 million in third quarter 2015
- Adjusted net income of $25 million for third quarter 2016 compared to adjusted net loss of $45 million in third quarter 2015

Nine Months

- Adjusted EBITDA, net of Noncontrolling Interest, was $169 million in the first nine months of 2016 compared to $510 million in first nine months of 2015, pro forma for divestitures
- Adjusted operating cash flow of ($60) million in the first nine months of 2016 compared to $302 million in the first nine months of 2015
- Adjusted net loss of $93 million in the first nine months of 2016 compared to adjusted net loss of $61 million in the first nine months of 2015

HEDGING UPDATE

During and after the third quarter, SandRidge added oil and natural gas hedge positions through the remainder of 2016, while also adding positions in both 2017 and 2018. For the calendar year of 2017, the Company now has approximately 2.6 million barrels of oil hedged at an average WTI price of $51.45 as well as 29.2 billion cubic feet of natural gas hedged at an average price of $3.19 per MMBtu. For 2018, the Company has approximately 1.1 million barrels of oil hedged at an average WTI price of $55.10.

GUIDANCE UPDATE

Capital expenditures in 2016 are now anticipated to be $220 to $240 million for the full year (midpoint reduced $10 million vs prior guidance), with production estimates ranging from 19.0 to 19.4 MMBoe (100 MBoe greater than prior guidance midpoint). The production estimate includes a 200 MBoe contingency for potential weather downtime as was experienced in late 2015.

The Company is in the process of developing its capital expenditures budget for 2017 and, in the current pricing environment, expects that total capital expenditures will be less than $200 million in 2017.

RESTRUCTURING DETAILS AND LIQUIDITY

- 20.6 million common shares outstanding
- 14.8 million shares issuable upon conversion of mandatory convertible notes
- 4.9 million warrants exercisable at $41.34 (net share settlement); 2.1 million warrants exercisable at $42.03 (net share settlement)
- No cash interest expense under current capital structure including undrawn revolver, $35 million secured building note and $278 million of zero interest bearing, mandatorily convertible notes
- $3.7 million par value of convertible notes converted as of October 31st
- No leverage or interest coverage financial covenants, only asset coverage ratio until October 2018
- No borrowing base redeterminations for approximately two years
- $536 million of liquidity as of October 31st, including $111 million of unrestricted cash and a $425 million undrawn revolver

NEW BOARD APPOINTMENTS

Effective October 4, 2016, the composition of SandRidge Energy's five person Board of Directors consisted of:

John V. Genova (Chairman) earned his Bachelor of Science degree in Chemical and Petroleum Refining Engineering from the Colorado School of Mines in 1976. He joined Exxon in the Company's Baton Rouge Refinery in 1976. At Exxon, he held a number of positions of increasing responsibility in the Refining, Supply and Natural Gas functions. Immediately following the public announcement of the Exxon and Mobil merger, Mr. Genova led the development of a $20 billion integrated natural gas project proposal for Saudi Arabia and served as the lead Exxon/Mobil merger natural gas negotiator with the European Commission. Following approval of the Exxon and Mobil merger, he was named Director, International Gas Marketing, ExxonMobil International Limited. Subsequently, he was appointed Executive Assistant to the Chairman, Lee Raymond, and the General Manager of Corporate Planning of Exxon Mobil Corporation on April 1, 2002. In this position, he served as an Officer of ExxonMobil. In April 2004, Mr. Genova became a Director of the Board of Encore Acquisition Company and served on the Audit Committee until the company's merger with Denbury Resources in early 2010. In May 2008, Mr. Genova was appointed as President and CEO of Sterling Chemicals where he led the creation of significant value before successfully completing the sale of the company to Eastman Chemical.

James D. Bennett has served as President and Chief Executive Officer of the Company since June 2013. Prior to commencing service in his current positions, he served as President and Chief Financial Officer from March 2013 until June 2013 and Executive Vice President and Chief Financial Officer from January 2011 until March 2013. Prior to joining the Company, Mr. Bennett was Managing Director for White Deer Energy, a private equity fund focused on the exploration and production, oilfield service and equipment, and midstream sectors of the oil and gas industry. From 2006 to 2009, Mr. Bennett was employed by GSO Capital Partners L.P., where he served in various capacities, including as its Managing Director. Mr. Bennett graduated with a B.B.A. with a major in finance from Texas Tech University. Mr. Bennett has served on the boards of directors of the general partner of Cheniere Energy Partners L.P. and PostRock Energy Corporation.

Michael (Mike) L. Bennett, no relation to James Bennett, has over thirty-six years of experience in the chemical industry and serves as a member of the board of directors and the audit committee of Alliant Energy, Chairman of the board of directors of OCI N.V., and Chairman of the board of directors of OCI Partners LP. Mr. Bennett served as President and CEO of Terra Industries, Inc. from 2001 until its sale to CF Industries in 2010. He is a past Chairman of The Fertilizer Institute and the Methanol Institute.

William (Bill) M. Griffin, Jr. is an independent energy advisor with over thirty-five years of technical and leadership experience with active public and privately owned upstream energy organizations. Mr. Griffin most recently served as President and Chief Executive Officer of privately held Petro Harvester Oil & Gas. Mr. Griffin's background also includes senior leadership positions as President of Ironwood Oil & Gas, Senior Vice President of El Paso Exploration and Production Company and Vice President of Sonat Exploration Company. In addition to the board of Petro Harvester, Mr. Griffin has also served as a director for Black Warrior Methane Corporation and Four Star Oil & Gas Company. Mr. Griffin began his career with Texas Oil & Gas Corporation and is a registered professional engineer with a B.S. in mechanical engineering from Texas A&M University.

David J. Kornder has over twenty-five years of experience and has previously served as Chief Executive Officer of Cornerstone Natural Resources, LLC, Chief Financial Officer of Petrie Parkman & Co., an energy investment bank, and as Executive Vice President and Chief Financial Officer of Patina Oil & Gas Corporation from 1996 through its acquisition by Noble Energy, Inc. in May 2005. Prior to that, Mr. Kornder began his career at Deloitte & Touche LLP.

CONFERENCE CALL DETAILS

The Company will host a conference call to discuss these results on Wednesday, November 9, 2016 at 8:00 am CT. The telephone number to access the conference call from within the U.S. is (877) 201-0168 and from outside the U.S. is (647) 788-4901. The passcode for the call is 86082124. An audio replay of the call will be available from November 9, 2016 until 11:59 pm CT on December 9, 2016. The number to access the conference call replay from within the U.S. is (855) 859-2056 and from outside the U.S. is (404) 537-3406. The passcode for the replay is 86082124.

OPERATIONAL AND FINANCIAL STATISTICS

Information regarding the Company's production, pricing, costs and earnings is presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Production - Total				
Oil (MBbl)	1,282	2,262	4,315	7,604
NGL (MBbl)	1,103	1,246	3,358	3,883
Natural gas (MMcf)	13,079	23,058	44,124	71,133
Oil equivalent (MBoe)	4,565	7,351	15,027	23,343
Daily production (MBoed)	49.6	79.9	54.8	85.5
Production - Mid-Continent				
Oil (MBbl)	998	1,938	3,597	6,554
NGL (MBbl)	1,084	1,202	3,301	3,764
Natural gas (MMcf)	13,016	20,128	43,330	62,292
Oil equivalent (MBoe)	4,250	6,495	14,119	20,700
Daily production (MBoed)	46.2	70.6	51.5	75.8
Average price per unit				
Realized oil price per barrel - as reported	$ 42.82	$ 43.33	$ 36.85	$ 47.55
Realized impact of derivatives per barrel	10.93	28.85	14.20	32.87
Net realized price per barrel	$ 53.75	$ 72.18	$ 51.05	$ 80.42
Realized NGL price per barrel - as reported	$ 13.90	$ 13.29	$ 12.67	$ 14.69
Realized impact of derivatives per barrel	-	-	-	-
Net realized price per barrel	$ 13.90	$ 13.29	$ 12.67	$ 14.69
Realized natural gas price per Mcf - as reported	$ 2.27	$ 2.19	$ 1.78	$ 2.20
Realized impact of derivatives per Mcf	0.05	0.09	(0.01)	0.41
Net realized price per Mcf	$ 2.32	$ 2.28	$ 1.77	$ 2.61
Realized price per Boe - as reported	$ 21.89	$ 22.46	$ 18.63	$ 24.65
Net realized price per Boe - including impact of derivatives	$ 25.10	$ 31.61	$ 22.70	$ 36.58
Average cost per Boe				
Lease operating	$ 8.68	$ 9.91	$ 8.63	$ 10.46
Production taxes	0.50	0.50	0.41	0.54
General and administrative				
General and administrative, excluding stock-based compensation	$ 3.99	$ 4.17	$ 7.00	$ 4.01
Stock-based compensation	2.40	0.49	1.94	0.65
Total general and administrative	$ 6.38	$ 4.66	$ 8.95	$ 4.66
General and administrative - adjusted				
General and administrative, excluding stock-based compensation [1]	$ 3.88	$ 3.29	$ 3.69	$ 3.37
Stock-based compensation [2]	0.98	0.48	0.71	0.44
Total general and administrative - adjusted	$ 4.86	$ 3.77	$ 4.40	$ 3.81
Depletion [3]	$ 6.07	$ 9.20	$ 6.05	$ 11.58
Lease operating cost per Boe				
Mid-Continent	$ 7.76	$ 7.09	$ 7.58	$ 7.75

[1] Excludes severance, doubtful receivable write-off and restructuring costs totaling $0.5 million and $49.8 million for the three and nine-month periods ended September 30, 2016, respectively. Excludes severance, legal settlements and shareholder litigation totaling $6.4 million and $14.9 million for the three and nine-month periods ended September 30, 2015, respectively.

[2] Three and nine-month periods ended September 30, 2016 exclude $6.5 million and $18.5 million,respectively, for employee incentive and retention and the acceleration of certain stock awards. Three and nine-month periods ended September 30, 2015 exclude $0.1 million and $4.8 million, respectively, for the acceleration of certain stock awards.

[3] Includes accretion of asset retirement obligation.

CAPITAL EXPENDITURES

The table below summarizes the Company's capital expenditures for the three and nine-month periods ended September 30, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Drilling and production				
Mid-Continent	$ 16,273	$ 87,183	$ 79,845	$ 511,789
Rockies	31,368	-	72,164	-
Other	(496)	675	65	4,257
	47,145	87,858	152,074	516,046
Leasehold and geophysical				
Mid-Continent	3,166	15,848	(2,771)	42,434
Rockies	594	-	1,361	-
Other	116	651	3,174	4,391
	3,876	16,499	1,764	46,825
Inventory	(443)	1,656	1,789	(3,356)
Total exploration and development	50,578	106,013	155,627	559,515
Drilling and oil field services	(248)	259	23	2,732
Midstream	1,166	3,719	3,085	20,400
Other - general	279	3,306	2,672	18,405
Total capital expenditures, excluding acquisitions	51,775	113,297	161,407	601,052
Acquisitions	(70)	(244)	1,327	3,231
Total capital expenditures	$ 51,705	$ 113,053	$ 162,734	$ 604,283

DERIVATIVE CONTRACTS

Subsequent to September 30, 2016, the Company entered into additional oil and gas swap contracts for the remainder of 2016, as well as for the calendar years of 2017 and 2018. The table below sets forth the Company's consolidated oil and natural gas price swaps and collars for 2016 as of November 8, 2016:

	4Q 2016
Oil (MMBbls):	
Swap Volume	1.29
Swap	$56.45
Natural Gas (Bcf):	
Swap Volume	10.92
Swap	$2.86
Natural Gas Basis (Bcf)	
Swap Volume	0.92
Swap	($0.38)

	Quarter Ending				
	3/31/2017	**6/30/2017**	**9/30/2017**	**12/31/2017**	**FY 2017**
Oil (MMBbls):					
Swap Volume	0.63	0.64	0.64	0.64	2.56
Swap	$51.45	$51.45	$51.45	$51.45	$51.45
Natural Gas (Bcf):					
Swap Volume	7.20	7.28	7.36	7.36	29.20
Swap	$3.19	$3.19	$3.19	$3.19	$3.19
	3/31/2018	**6/30/2018**	**9/30/2018**	**12/31/2018**	**FY 2018**
Oil (MMBbls):					
Swap Volume	0.27	0.27	0.28	0.28	1.10
Swap	$55.10	$55.10	$55.10	$55.10	$55.10

BALANCE SHEET

The Company's capital structure, pro forma for its restructuring and as of October 31, 2016 is presented below.

Proforma Capital Structure	$ in Millions		
Debt at Principal Value	**as of Jun 30, 2016**	**Restructuring**	**Pro Forma as of Oct 31, 2016**
Secured Debt[1]	$ -	$ 35	$ 35
8.75% Second Lien Secured Notes due 2020	1,328	(1,328)	-
Unsecured Notes:			
8.75% Senior Unsecured Notes due 2020	$ 396	$ (396)	$ -
7.50% Senior Unsecured Notes due 2021	758	(758)	-
8.125% Senior Unsecured Notes due 2022	528	(528)	-
7.50% Senior Unsecured Notes due 2023	544	(544)	-
Sub-Total Unsecured Notes	$ 2,225	$ (2,225)	$ -
Unsecured Convertible Notes:			
8.125% Senior Unsecured Convertible Notes due 2022	$ 41	$ (41)	$ -
7.50% Senior Unsecured Convertible Notes due 2023	47	(47)	-
Total Senior Debt	**$ 3,641**	**$ (3,606)**	**$ 35**
0.00% Convertible Senior Subordinated Notes Due 2020[2]	$ -	$ 278	$ 278
Total Debt	**$ 3,641**	**$ (3,328)**	**$ 313**
Liquidity			
RBL Borrowing Base[3]	$ 500	$ (75)	$ 425
RBL Available	-	425	425
Cash	634	(523)	111
Total Liquidity	**$ 634**	**$ (98)**	**$ 536**

1) Secured by mortgages on the Company's non-oil and gas real property.
2) $3.7 million par value of conversions as of October 31st.
3) Excludes approximately $10 million of letters of credit.

2016 OPERATIONAL GUIDANCE UPDATE

The Company is providing an update to its previously disclosed 2016 capital budgeting guidance from $225 to $255 million, estimating that it will now spend $220 to $240 million for the full year with total production ranging from 19.0 to 19.4 MMBoe. Capital expenditure, production, and other operational guidance detail for the full year of 2016 can be found below.

	Total Company Projection as of September 28, 2016	Total Company Projection as of November 8, 2016
Production		
Oil (MMBbls)	5.3 - 5.5	***5.4 - 5.5***
Natural Gas Liquids (MMBbls)	4.1 - 4.3	4.1 - 4.3
Total Liquids (MMBbls)	9.4 - 9.8	***9.5 - 9.8***
Natural Gas (Bcf)	56.7 - 56.8	***57.0 - 57.3***
Total (MMBoe)	18.9 - 19.3	***19.0 - 19.4***
Price Realization		
Oil (differential below NYMEX WTI)	$3.75	$3.75
Natural Gas Liquids (realized % of NYMEX WTI)	27%	***30%***
Natural Gas (differential below NYMEX Henry Hub)	$0.50	$0.50
Costs per Boe		
LOE	$9.00 - $9.20	***$8.80 - $9.00***
DD&A - oil & gas[1]	5.10 - 5.50	***5.80 - 6.20***
DD&A - other	1.40 - 1.45	1.40 - 1.45
Total DD&A	$6.50 - $6.95	***$7.20 - $7.65***
Adjusted G&A - Cash[2]	$4.25 - $4.50	***$3.70 - $3.90***
% of Revenue		
Production Taxes	2.00% - 2.25%	2.00% - 2.25%
Corporate Tax Rate	0%	0%
Deferral Tax Rate	0%	0%

Capital Expenditures ($ in millions)

Drilling and Completing	**Previous**	**New**
Mid-Continent	$45 - $50	***$42.5 - $47.5***
North Park Basin	55 - 60	55 - 60
Other[3]	25 - 30	***25***
Total Drilling and Completing	**$125 - $140**	***$122.5 - $132.5***
Other E&P		
Land, G&G, and Seismic	$10 - $15	$10 - $15
Infrastructure[4]	25 - 30	***20 - 22.5***
Workover	35 - 40	***37.5 - 40***
Capitalized G&A and Interest	25	25
Total Other Exploration and Production	**$95 - $110**	***$92.5 - $102.5***
General Corporate	$5	$5
Total Capital Expenditures (excluding acquisitions and abandonment liabilities)	**$225 - $255**	***$220 - $240***

1) May be materially affected at year end by application of Fresh Start accounting.
2) Adjusted G&A - Cash is a non-GAAP financial measure as it excludes from G&A non-cash compensation, severance, bad debt allowance, shareholder litigation costs, restructuring costs, and other non-recurring items. Incentive compensation plan normalized to be consistent with prior year compensation plans. The most directly comparable GAAP measure for Adjusted G&A - cash is General and Administrative Expense. Information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to forecast the excluded items for future periods.
3) 2015 Carryover, JV Penalty, Rig Penalty, Non-Op, SWD
4) Facilities - Electrical, SWD, Gathering, Pipelines

SANDRIDGE ENERGY, INC. AND SUBSIDIARIES (DEBTOR-IN-POSSESSION)
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(IN THOUSANDS)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(unaudited)			
Revenues				
Oil, natural gas and NGL	$ 99,934	$ 165,135	$ 279,971	$ 575,399
Midstream and marketing	3,004	8,838	10,545	26,208
Drilling and services	886	4,572	2,342	19,658
Other	232	1,607	951	3,802
Total revenues	104,056	180,152	293,809	625,067
Expenses				
Production	39,640	72,884	129,608	244,158
Production taxes	2,278	3,652	6,107	12,548
Cost of sales	563	4,323	5,302	22,034
Midstream and marketing	-	6,633	1,840	22,464
Depreciation and depletion - oil and natural gas	26,335	66,501	86,613	266,906
Depreciation and amortization - other	7,514	11,379	21,323	37,234
Accretion of asset retirement obligations	1,390	1,132	4,365	3,323
Impairment	354,451	1,074,588	718,194	3,647,845
General and administrative	29,145	34,233	134,447	108,764
(Gain) loss on derivative contracts	(338)	(42,211)	4,823	(59,034)
Loss on settlement of contract	-	-	90,184	-
Loss (gain) on sale of assets	416	6,771	(2,794)	2,097
Total expenses	461,394	1,239,885	1,200,012	4,308,339
Loss from operations	(357,338)	(1,059,733)	(906,203)	(3,683,272)
Other (expense) income				
Interest expense (excludes $36.9 million and $74.5 million of contractual interest expense on debt subject to compromise for the three and nine-month periods ended September 30, 2016, respectively)	(3,343)	(77,000)	(126,099)	(213,569)
Gain on extinguishment of debt	-	340,699	41,179	358,633
Reorganization items, net	(42,754)	-	(243,672)	-
Other (expense) income, net	(898)	(426)	1,332	1,208
Total other (expense) income	(46,995)	263,273	(327,260)	146,272
Loss before income taxes	(404,333)	(796,460)	(1,233,463)	(3,537,000)
Income tax expense	4	25	11	90
Net loss	(404,337)	(796,485)	(1,233,474)	(3,537,090)
Less: net loss attributable to noncontrolling interest	-	(156,073)	-	(493,243)
Net loss attributable to SandRidge Energy, Inc.	(404,337)	(640,412)	(1,233,474)	(3,043,847)
Preferred stock dividends	-	9,114	16,321	27,069
Loss applicable to SandRidge Energy, Inc. common stockholders	$ (404,337)	$ (649,526)	$ (1,249,795)	$ (3,070,916)

SANDRIDGE ENERGY, INC. AND SUBSIDIARIES (DEBTOR-IN-POSSESSION)
CONDENSED CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

	September 30, 2016	December 31, 2015
	(unaudited)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 652,680	$ 435,588
Accounts receivable, net	61,446	127,387
Derivative contracts	10,192	84,349
Prepaid expenses	12,514	6,833
Other current assets	1,003	19,931
Total current assets	737,835	674,088
Oil and natural gas properties, using full cost method of accounting		
Proved	12,093,492	12,529,681
Unproved	322,580	363,149
Less: accumulated depreciation, depletion and impairment	(11,637,538)	(11,149,888)
	778,534	1,742,942
Other property, plant and equipment, net	357,528	491,760
Derivative contracts	70	-
Other assets	12,537	13,237
Total assets	$ 1,886,504	$ 2,922,027
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities		
Accounts payable and accrued expenses	$ 140,448	$ 428,417
Derivative contracts	2,982	573
Asset retirement obligations	8,573	8,399
Total current liabilities	152,003	437,389
Long-term debt	-	3,562,378
Derivative contracts	935	-
Asset retirement obligations	62,896	95,179
Other long-term obligations	3	14,814
Liabilities subject to compromise	4,346,188	-
Total liabilities	4,562,025	4,109,760
Commitments and contingencies		
Equity (deficit)		
SandRidge Energy, Inc. stockholders' equity (deficit)		
Preferred stock, $0.001 par value, 50,000 shares authorized		
8.5% Convertible perpetual preferred stock; 2,650 shares issued and outstanding at September 30, 2016 and December 31, 2015; aggregate liquidation preference of $265,000	3	3
7.0% Convertible perpetual preferred stock; 2,597 shares issued and outstanding at September 30, 2016: aggregate liquidation preference of $259,700; 2,770 shares issued and outstanding at December 31, 2015: aggregate liquidation preference of $277,000	3	3
Common stock, $0.001 par value; 1,800,000 shares authorized; 720,936 issued and 719,425 outstanding at September 30, 2016 and 635,584 issued and 633,471 outstanding at December 31, 2015	718	630
Additional paid-in capital	5,315,655	5,301,136
Additional paid-in capital - stockholder receivable	(1,250)	(1,250)
Treasury stock, at cost	(5,218)	(5,742)
Accumulated deficit	(7,985,411)	(6,992,697)
Total SandRidge Energy, Inc. stockholders' deficit	(2,675,500)	(1,697,917)
Noncontrolling interest	(21)	510,184
Total stockholders' deficit	(2,675,521)	(1,187,733)
Total liabilities and stockholders' deficit	$ 1,886,504	$ 2,922,027

SANDRIDGE ENERGY, INC. AND SUBSIDIARIES (DEBTOR-IN-POSSESSION)
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	Nine Months Ended September 30,	
	2016	2015
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (1,233,474)	$ (3,537,090)
Adjustments to reconcile net loss to net cash (used in) provided by operating activities		
Provision for doubtful accounts	16,704	-
Depreciation, depletion and amortization	107,936	304,140
Accretion of asset retirement obligations	4,365	3,323
Impairment	718,194	3,647,845
Reorganization items, net	231,836	-
Debt issuance costs amortization	4,996	8,324
Amortization of discount, net of premium, on debt	2,734	1,053
Gain on extinguishment of debt	(41,179)	(358,633)
Write off of debt issuance costs	-	7,108
Gain on debt derivatives	(1,324)	(10,146)
Cash paid for early conversion of convertible notes	(33,452)	(2,708)
Loss (gain) on derivative contracts	4,823	(59,034)
Cash received on settlement of derivative contracts	72,608	278,581
Loss on settlement of contract	90,184	-
Cash paid on settlement of contract	(11,000)	-
(Gain) loss on sale of assets	(2,794)	2,097
Stock-based compensation	9,075	15,170
Other	(466)	1,772
Changes in operating assets and liabilities	(3,805)	59,084
Net cash (used in) provided by operating activities	(64,039)	360,886
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures for property, plant and equipment	(186,452)	(761,905)
Acquisition of assets	(1,328)	(3,231)
Proceeds from sale of assets	20,090	35,387
Net cash used in investing activities	(167,690)	(729,749)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings	489,198	2,190,000
Repayments of borrowings	(40,000)	(1,034,466)
Debt issuance costs	(333)	(48,021)
Noncontrolling interest distributions	-	(115,301)
Purchase of treasury stock	(44)	(3,198)
Dividends paid - preferred	-	(11,262)
Net cash provided by financing activities	448,821	977,752
NET INCREASE IN CASH AND CASH EQUIVALENTS	217,092	608,889
CASH AND CASH EQUIVALENTS, beginning of year	435,588	181,253
CASH AND CASH EQUIVALENTS, end of period	$ 652,680	$ 790,142
Supplemental Disclosure of Cash Flow Information		
Cash paid for reorganization items	$ (11,836)	$ -
Supplemental Disclosure of Noncash Investing and Financing Activities		
Cumulative effect of adoption of ASU 2015-02	$ (247,566)	$ -
Property, plant and equipment transferred in settlement of contract	$ (215,635)	$ -
Change in accrued capital expenditures	$ 25,045	$ 160,853
Equity issued for debt	$ 4,409	$ (35,147)
Preferred stock dividends paid in common stock	$ -	$ (16,188)

NON-GAAP FINANCIAL MEASURES

Adjusted operating cash flow, adjusted EBITDA, pro forma adjusted EBITDA and adjusted net loss are non-GAAP financial measures.

The Company defines adjusted operating cash flow as net cash provided by (used in) operating activities before changes in operating assets and liabilities. It defines EBITDA as net loss before income tax expense, interest expense and depreciation, depletion and amortization and accretion of asset retirement obligations. Adjusted EBITDA, as presented herein, is EBITDA excluding asset impairment, interest income, loss (gain) on derivative contracts net of cash received upon settlement of derivative contracts, loss on settlement of contract, loss (gain) on sale of assets, legal settlements, severance, oil field services – exit costs, gain on extinguishment of debt, restructuring costs, reorganization items and other various items (including non-cash portion of noncontrolling interest and stock-based compensation). Pro forma adjusted EBITDA, as presented herein, is adjusted EBITDA excluding adjusted EBITDA attributable to properties or subsidiaries sold during the period.

Adjusted operating cash flow and adjusted EBITDA are supplemental financial measures used by the Company's management and by securities analysts, investors, lenders, rating agencies and others who follow the industry as an indicator of the Company's ability to internally fund exploration and development activities and to service or incur additional debt. The Company also uses these measures because adjusted operating cash flow and adjusted EBITDA relate to the timing of cash receipts and disbursements that the Company may not control and may not relate to the period in which the operating activities occurred. Further, adjusted operating cash flow and adjusted EBITDA allow the Company to compare its operating performance and return on capital with those of other companies without regard to financing methods and capital structure. These measures should not be considered in isolation or as a substitute for net cash provided by operating activities prepared in accordance with generally accepted accounting principles ("GAAP"). Adjusted EBITDA should not be considered as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, the Company's adjusted EBITDA may not be comparable to similarly titled measures used by other companies.

Management also uses the supplemental financial measure of adjusted net income (loss), which excludes asset impairment, (loss) gain on derivative contracts net of cash received on settlement of derivative contracts, loss on settlement of contract, gain on sale of assets, severance, oil field services – exit costs, gain on extinguishment of debt, restructuring costs, reorganization items, employee incentive and retention and other non-cash items from loss applicable to common stockholders. Management uses this financial measure as an indicator of the Company's operational trends and performance relative to other oil and natural gas companies and believes it is more comparable to earnings estimates provided by securities analysts. Adjusted net income (loss) is not a measure of financial performance under GAAP and should not be considered a substitute for loss applicable to common stockholders.

The tables below reconcile the most directly comparable GAAP financial measures to operating cash flow, EBITDA and adjusted EBITDA and adjusted net loss.

RECONCILIATION OF CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES TO ADJUSTED OPERATING CASH FLOW

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Net cash provided by (used in) operating activities	$ 75,002	$ 41,892	$ (64,039)	$ 360,886
Changes in operating assets and liabilities	(43,215)	2,673	3,805	(59,084)
Adjusted operating cash flow	$ 31,787	$ 44,565	$ (60,234)	$ 301,802

RECONCILIATION OF NET LOSS TO EBITDA AND ADJUSTED EBITDA

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Net loss	$ (404,337)	$ (640,412)	$ (1,233,474)	$ (3,043,847)
Adjusted for				
Income tax expense	4	25	11	90
Interest expense	3,589	77,501	127,517	214,198
Depreciation and amortization - other	7,514	11,379	21,323	37,234
Depreciation and depletion - oil and natural gas	26,335	66,501	86,613	266,906
Accretion of asset retirement obligations	1,390	1,132	4,365	3,323
EBITDA	(365,505)	(483,874)	(993,645)	(2,522,096)
Asset impairment	354,451	1,074,588	718,194	3,647,845
Interest income	(246)	(501)	(1,418)	(629)
Stock-based compensation	1,247	3,203	4,291	9,294
(Gain) loss on derivative contracts	(338)	(42,211)	4,823	(59,034)
Cash received upon settlement of derivative contracts [1]	20,393	67,258	66,851	278,581
Loss on settlement of contract	-	-	90,184	-
Loss (gain) on sale of assets	416	6,771	(2,794)	2,097
Legal settlement	-	5,122	-	4,994
Severance	55	1,290	17,541	11,819
Oil field services - exit costs	12	62	2,428	4,353
Gain on extinguishment of debt	-	(340,699)	(41,179)	(358,633)
Restructuring costs	421	-	18,865	-
Reorganization items, net	42,754	-	243,672	-
Employee incentive and retention	9,724	-	20,141	-
Other	1,351	935	19,032	3,676
Non-cash portion of noncontrolling interest [2]	-	(174,304)	-	(561,969)
Adjusted EBITDA	$ 64,735	$ 117,640	$ 166,986	$ 460,298
Less: EBITDA attributable to WTO properties (2016)	-	16,644	1,990	49,502
Pro forma adjusted EBITDA	$ 64,735	$ 134,284	$ 168,976	$ 509,800

(1) Excludes amounts received upon early settlement of contracts for 2016 period.

(2) Represents depreciation and depletion, impairment, gain on commodity derivative contracts net of cash received on settlement and income tax expense attributable to noncontrolling interests in the 2015 period.

RECONCILIATION OF CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES TO ADJUSTED EBITDA

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Net cash provided by (used in) operating activities	$ 75,002	$ 41,892	$ (64,039)	$ 360,886
Changes in operating assets and liabilities	(43,215)	2,673	3,805	(59,084)
Interest expense	3,589	77,501	127,517	214,199
Cash received on early settlement of derivative contracts	-	-	(17,894)	-
Contractual maturity reached on previous early settlements	5,756	-	12,137	-
Cash paid on early conversion of convertible notes	-	2,709	33,452	2,709
Cash paid on settlement of contract	-	-	11,000	-
Legal settlements	-	5,122	-	4,994
Severance [1]	77	1,156	12,463	7,004
Oil field services - exit costs [1]	13	62	2,386	4,275
Restructuring costs	421	-	18,865	-
Cash paid for reorganization items	11,836	-	11,836	-
Employee incentive and retention	9,724	-	20,141	-
Noncontrolling interest - SDT [2]	-	(6,619)	-	(19,237)
Noncontrolling interest - SDR [2]	-	(4,918)	-	(16,277)
Noncontrolling interest - PER [2]	-	(6,694)	-	(33,212)
Other	1,532	4,756	(4,683)	(5,959)
Adjusted EBITDA	$ 64,735	$ 117,640	$ 166,986	$ 460,298

[1] Excludes associated stock-based compensation.

[2] Excludes depreciation and depletion, impairment, gain on commodity derivative contracts net of cash received on settlement and income tax expense attributable to noncontrolling interests for 2015 period.

RECONCILIATION OF NET LOSS APPLICABLE TO COMMON STOCKHOLDERS TO ADJUSTED NET INCOME AVAILABLE (LOSS APPLICABLE) TO COMMON STOCKHOLDERS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(in thousands)			
Loss applicable to common stockholders	$ (404,337)	$ (649,526)	$ (1,249,795)	$ (3,070,916)
Asset impairment [1]	354,451	907,834	718,194	3,127,684
(Gain) loss on derivative contracts [1]	(338)	(38,438)	4,823	(53,926)
Cash received upon settlement of derivative contracts [1][2]	20,393	60,342	66,851	249,665
Loss on settlement of contract	-	-	90,184	-
Loss (gain) on sale of assets	416	6,771	(2,794)	2,097
Legal settlements	-	5,122	-	4,994
Severance	55	1,290	17,541	11,819
Oil field services - exit costs	12	62	2,428	4,353
Gain on extinguishment of debt	-	(340,699)	(41,179)	(358,633)
Restructuring costs	421	-	18,865	-
Reorganization items, net	42,754	-	243,672	-
Employee incentive and retention	9,724	-	20,141	-
Other	1,780	(10,306)	18,194	(8,243)
Effect of income taxes	4	19	10	76
Adjusted net income available (loss applicable) to common stockholders	25,335	(57,529)	(92,865)	(91,030)
Preferred stock dividends [3]	-	9,114	-	27,069
Effect of convertible debt, net of income taxes [3]	-	2,918	-	2,918
Total adjusted net income (loss)	$ 25,335	$ (45,497)	$ (92,865)	$ (61,043)

[1] Excludes amounts attributable to noncontrolling interests for 2015 period.

[2] Excludes amounts received for early settlement of contracts for 2016 period.

[3] Not considered dilutive securities in 2016 periods.

FOR FURTHER INFORMATION, PLEASE CONTACT:

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Cautionary Note to Investors - This press release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, including, but not limited to, the information appearing under the heading "Operational Guidance." These statements express a belief, expectation or intention and are generally accompanied by words that convey projected future events or outcomes. The forward-looking statements include projections and estimates of the Company's corporate strategies, future operations, net income and EBITDA, drilling plans, oil, and natural gas and natural gas liquids production, price realizations and differentials, reserves, operating, general and administrative and other costs, capital expenditures, tax rates, efficiency and cost reduction initiative outcomes, infrastructure utilization and investment, and development plans and appraisal programs. We have based these forward-looking statements on our current expectations and assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including the volatility of oil and natural gas prices, our success in discovering, estimating, developing and replacing oil and natural gas reserves, actual decline curves and the actual effect of adding compression to natural gas wells, the availability and terms of capital, the ability of counterparties to transactions with us to meet their obligations, our timely execution of hedge transactions, credit conditions of global capital markets, changes in economic conditions, the amount and timing of future development costs, the availability and demand for alternative energy sources, regulatory changes, including those related to carbon dioxide and greenhouse gas emissions, and other factors, many of which are beyond our control. We refer you to the discussion of risk factors in Part I, Item 1A - "Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2015 and in comparable "Risk Factor" sections of our Quarterly Reports on Form 10-Q filed after such form 10-K. All of the forward-looking statements made in this press release are qualified by these cautionary statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on our Company or our business or operations. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in the forward-looking statements. We undertake no obligation to update or revise any forward-looking statements.

SandRidge Energy, Inc. (NYSE: SD) is an oil and natural gas exploration and production company headquartered in Oklahoma City, Oklahoma with its principal focus on developing high-return, growth-oriented projects in the U.S. Mid-Continent and Niobrara Shale.