

Jones Energy, Inc. Provides Operations Update, 2017 Year-End Reserves and 2018 Guidance

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AUSTIN, Texas, Feb. 05, 2018 (GLOBE NEWSWIRE) -- [Jones Energy Inc.](#) (NYSE:JONE) ("Jones Energy" or "the Company") today provided its 2017 year-end reserves, an operations update and initial 2018 guidance.

Highlights

- Bone 2H Meramec well achieves peak IP24 rate of 1,878 Boe/d (54% oil, 3-stream). Peak oil rate of 1,015 Bo/d or 232 Bbls per 1,000' of lateral, sets new Company record in the Merge.
- Fourth quarter 2017 average production of approximately 21,200 Boe/d, 6.5% above the midpoint of guidance. Full year 2017 average production of approximately 21,300 Boe/d, beating the high end of the guidance.
- Proved oil reserves increased 23% to 29 MMBbls from year-end 2016.
- Year-end 2017 proved reserves standardized measure value of \$567 million increased 48% from year-end 2016. Corresponding Non-GAAP SEC PV-10¹ value of \$627 million increased 56% from year-end 2016, based on SEC prices².
- Initial 2018 capital budget of \$150 million.
- 2018 full-year production guidance of 19,300 to 21,500 Boe/d; first quarter 2018 production guidance of 19,200 to 21,400 Boe/d.

Jones Energy Founder, Chairman, and CEO, Jonny Jones stated, "I am proud to announce our year-end 2017 reserves, which highlight just how large a contribution the Merge has already made to our Company. Reserves and PV-10 value grew significantly in 2017 from the Merge, and we are very excited with the results we are seeing from this new asset." Mr. Jones further stated, "In fact, today we are announcing initial production rates from our two-well Bone pad, which are exceeding type curves and setting new records for the Company. We continue to see strong early-time production from our existing Merge wells and I look forward to providing additional details on our operations with our fourth quarter and full year 2017 earnings. Finally, I'd like to announce our initial 2018 capital budget of \$150 million, which is focused on Merge development. This budget will allow us to hold-by-production ("HBP") all of our majority-owned sections in the Merge and, with a moderate cash flow outspend, grow production over 2017³."

2017 Year-End Proved Reserves

Jones Energy's year-end 2017 proved reserves based on SEC pricing were 104.8 MMBoe, of which 59% were classified as proved developed reserves. Total proved oil reserves at year-end 2017 were 29.0 MMBbls, an increase of 23% from year end 2016 reserves of 23.6 MMBbls. The SEC standardized measure value of the Company's proved reserves was \$567 million. Its PV-10 value of proved reserves (a non-GAAP measure) for year-end 2017 was \$627 million.

The following tables set forth the Company's total proved reserves and the changes in the Company's total proved reserves. These estimates are based on reports prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. Year-end proved reserves were determined utilizing a WTI oil price of \$51.34 per barrel and a Henry Hub spot market natural gas price of \$2.96 per MMBtu as prescribed by the SEC.

Proved Reserves as of December 31, 2017

	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Total (MMBoe)	% Liquids (Oil & NGLs)	
Eastern Anadarko ⁴	9.6	60.9	8.6	28.3	64	%
Western Anadarko ⁵	19.5	193.8	24.7	76.4	58	%
Other	0.0	0.5	0.0	0.1	24	%
Total Proved	29.0	255.1	33.3	104.8	59	%
Proved Developed	15.4	159.5	20.2	62.2	57	%

Assuming strip pricing as of January 2, 2018, through 2023 and keeping pricing flat thereafter, instead of 2017 SEC pricing, while leaving all other parameters unchanged, the Company's proved reserves would have been 105.7 MMBoe, and the corresponding NYMEX PV-10⁶ would have been \$721 million. This alternative pricing scenario is provided only to demonstrate the impact that the current pricing environment may have on reserve volumes and SEC PV-10 value. There is no assurance that these prices will actually be realized.

Changes in Proved Reserves (MMBoe)

Proved reserves as of December 31, 2016	105.2
Extensions and discoveries	28.7
Production ⁷	(7.7)
Purchases of Minerals in Place	―
Sales of Minerals in Place	(13.7)
Revisions of previous estimates	(7.7)
Proved reserves as of December 31, 2017	104.8

As of December 31, 2017, the Company had 1,044 gross producing wells and 7,180 gross drilling locations⁸. These include approximately 5,443 gross drilling locations in the Merge, consisting of 3,280 Woodford locations and 2,163 Meramec locations.

The following table presents summary proved reserves and production data for each of our core operating areas:

	As of December 31, 2017				Quarter Ended December 31, 2017		Year Ended December 31, 2017		
	Net Proved Reserves				Average Daily Net Production		Average Daily Net Production		
	MMBoe	% Oil &	NGLs	PV-10 ⁽²⁾ (\$MM)	MBoe/d	% of Production	MBoe/d	% of Production	
Eastern Anadarko	28.3	64 %		\$226.8	5.0	24 %	2.8	13 %	
Western Anadarko	76.4	58 %		400.0	15.0	71 %	15.2	71 %	
Other	0.1	24 %		(0.2)	1.2	5 %	3.3	16 %	
All Properties	104.8	59 %		\$626.6	21.2	100 %	21.3	100 %	

Operations Update

Recent Merge Well Results

Jones Energy is announcing initial production rates for its two-well Bone pad, located in Southern Canadian County, OK consisting of one Meramec and one Woodford well. The Bone 1H, a Woodford well drilled to a 4,322' lateral length, achieved a peak IP24 rate of 755 Boe/d (63% oil on a 3-stream basis). The Bone 2H, a Meramec well drilled to a 4,375' lateral length, achieved a peak IP24 rate of 1,878 Boe/d (54% oil on a 3-stream basis). Both Bone wells are exhibiting high oil cuts in early time data, confirming the up-dip oil fairway across the Merge. In fact, the Bone 2H Meramec well had a peak oil rate of 1,015 Bo/d, which is 232 Bbls per 1,000' of lateral, setting new Company record for oil rate per 1,000' of lateral in the Merge.

The following table sets forth certain information related to all of the wells the Company has drilled and

completed in the Merge that have achieved peak 30-day initial production rates (“IP”), except as noted below for the two-well Bone pad. Results are reported on a 3-stream basis. In addition, as of February 1, 2018, we had completed 10 wells in the Merge that have not yet achieved peak 30-day IP.

Date of First Production	Lateral Length (feet)	Peak 24 Hour IP (Boe/d) ⁽²⁾	% Oil	Peak 30 Day IP (Boe/d) ⁽²⁾	% Oil
Meramec:					
Bone 1H 5/30/2017	4,428	2,050	32 %	1,609	34
Gauley 6/24/2017	4,697	1,317	53 %	1,202	51
Norfolk 8/1/2017	4,576	1,346	20 %	1,202	20
Hardy 10/5/2017	4,586	979	46 %	796	39
Rodney 10/10/2017	4,579	1,363	40 %	1,234	38
Rodney 10/20/2017	4,586	1,615	36 %	1,483	35
Hardy 10/25/2017	4,476	1,249	41 %	1,004	32
Bone 12/14/2017	4,375	1,878	54 %	1,665	⁽¹⁾ 50
Average	4,538	1,475	40 %	1,274	37
Woodford:					
Bone 8/10/2017	4,346	327	31 %	285	25
Hardy 8/13/2017	4,370	619	55 %	474	52
Bell 4/6/2017	4,895	375	83 %	185	76
Bone 5/18/2017	4,196	1,110	25 %	941	25
Hardy 10/23/2017	4,362	1,011	48 %	549	50
Rodney 10/22/2017	4,382	970	42 %	878	40
Bone 12/14/2017	4,322	755	63 %	564	⁽¹⁾ 63
Average	4,410	738	50 %	554	47

(1) This well has achieved peak 30-day oil IP but has not yet achieved peak 30-day gas IP.

(2) Reported on a 3-stream basis, including oil, natural gas and NGLs.

For the full year 2017, Jones Energy drilled 41 gross (38.3 net) wells in the Cleveland formation and 27 gross (17.4 net) wells in the Merge. The Company continues to run two rigs in the Merge and is not running any rigs in the Western Anadarko at this time.

Fourth Quarter and Full Year 2017 Update

Production Update for the Fourth Quarter and Full Year 2017

The Company produced 21,207 Boe/d in the fourth quarter of 2017, which is 6.5% above the midpoint of company guidance. Oil volumes exceeded the high end of guidance and were 6,217 Bo/d, or 29% of total production. NGL volumes represented 30% of fourth quarter production.

Jones Energy produced 21,332 Boe/d for the full year 2017, which is above the high end of guidance. Average oil volumes of 5,378 Bo/d comprised 25% of production and NGL volumes accounted for 31% of the full year production. For the full year 2017, the Company’s production grew 11% as compared to average 2016 production.

Capital Expenditures Update for the Fourth Quarter and Full Year 2017

During the fourth quarter of 2017, the Company’s capital expenditures totaled \$63.3 million, of which \$57.3 million, or 91%, was related to drilling and completing operated wells. The remaining \$6.0 million was

primarily related to participation in non-op drilling.

For the full year 2017, total capital expenditures were \$248.0 million, of which \$205.7 million (or 83%) was related to drilling and completing wells. Total Merge spending was \$126 million for the full year.

2018 Capital Budget and Operating Plan

Jones Energy is announcing an initial capital budget of \$150 million for 2018, with approximately \$119 million dedicated to Company operated drilling and completion activities. This budget represents a 40% reduction in capital expenditures from 2017 and is allocated primarily to a development program in the Merge. The Company is running two rigs in the Merge today and plans to drill a total of 20 gross wells in the program in 2018 assuming an average working interest of approximately 65%. The Company has budgeted \$11 million for drilling the Western Anadarko asset. Jones Energy believes that the 2018 budget will allow it to HBP all sections where it owns a majority working interest position.

New Merge Midstream Contracts Expected to Improve Differentials

Jones Energy has entered into a new midstream contract covering its Merge asset effective January 1, 2018 that it believes will provide meaningful improvements to pricing differentials. The new contract is expected to reduce the Company's total wet gas fees by approximately 20 percent.

Initial 2018 Guidance

Based upon the initial 2018 capital budget and operating plan, the Company is projecting 2018 average daily production of between 19,300 and 21,500 Boe/d. Because the Company is drilling both long laterals and multi-well pads, which have longer lead-times and will require offset shut-ins for fracs, production is expected to fluctuate throughout the year. A table has been provided below with full year and first quarter 2018 guidance by category:

2018 Guidance

	2018E
Total Production (MMBoe)	71.7 – 71.9
Average Daily Production (MBoe/d)	19.3 – 21.5
Crude Oil (MBbl/d)	5.6 – 6.2
Natural Gas (MMcf/d)	46.4 – 51.5
NGLs (MBbl/d)	6.0 – 6.7
Lease Operating Expense (\$mm)	\$43.0 – \$46.0
Production Taxes (% of Unhedged Revenue) *	4.0% – 4.5%
Ad Valorem Taxes (\$mm) *	\$1.0 – \$2.0
Cash G&A Expense (\$mm)	\$22.0 – \$24.0
Capital Expenditures (\$mm)	
Merge D&C Operated	\$108
Merge D&C Non-operated	15
Cleveland D&C	11
Other (pooling, leasing & maintenance)	16
Total Capital Expenditures	\$150

* Production and ad valorem taxes are included as one line-item on the Company's Consolidated Statements of Operations.

Hedging Update

The following table summarizes the Company's net commodity derivative contracts outstanding as of February 5, 2018:

	2018	2019	2020
Oil Hedges			
Swaps Sold (MBbl)	2,364	1,020	660
Price (\$/Bbl)	\$51.08	\$50.04	\$50.00
Collars (MBbl)	-	810	-
Floor (\$/Bbl)	-	\$48.52	-
Ceiling (\$/Bbl)	-	\$59.64	-
Gas Hedges			
Swaps Sold (MMcf)	18,190	7,260	8,400
Price (\$/Mcf)	\$2.98	\$2.84	\$2.79
Collars (MMcf)	-	11,890	-
Floor (\$/Mcf)	-	\$2.55	-
Ceiling (\$/Mcf)	-	\$3.19	-
NGL Swaps (MBbl)			
Ethane	-	-	-
Propane	850	-	-
Iso Butane	120	-	-
Butane	335	-	-
Natural Gasoline	360	-	-
Total NGLs	1,665	-	-
NGL Swap Prices (\$/Gal)			
Ethane	-	-	-
Propane	0.57	-	-
Iso Butane	0.72	-	-
Butane	0.69	-	-
Natural Gasoline	1.05	-	-
Basis Hedges:			
ANR (MMcf)	6,000	-	-
Price (\$/Mcf)	\$0.40	-	-
PEPL (MMcf)	2,000	-	-
Price (\$/Mcf)	\$0.45	-	-

¹ SEC PV-10 is a supplemental Non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements. For additional information, including a reconciliation to standardized measure, the most comparable GAAP financial measure, please see "Non-GAAP Financial Measures and Reconciliations" below.

² SEC prices for 2017 year-end proved reserves were \$51.34 per barrel for oil and \$2.96 per MMBtu for natural gas based on the average of such prices for 2017.

³ Year over year production growth comparison is net of Arkoma divestiture representing approximately 1.6 MBoe/d of 2017 total production.

⁴ Eastern Anadarko consists of the Merge.

⁵ Western Anadarko includes the Cleveland, Granite Wash, Tonkawa and Marmaton.

⁶ NYMEX PV-10 is a supplemental Non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements. For additional information, including a reconciliation to standardized measure, the most comparable GAAP financial measure, please see "Non-GAAP Financial Measures and Reconciliations" below.

⁷ Production amount is an estimate pending final audit results by the Company's outside auditor.

⁸ Company identified gross drilling locations based on Total Proved Undeveloped, Probable and Possible ("3P") locations.

About Jones Energy

[Jones Energy Inc.](http://www.jonesenergy.com) is an independent oil and natural gas company engaged in the development and acquisition of oil and natural gas properties in the Anadarko basin of Oklahoma and Texas. Additional information about Jones Energy may be found on the Company's website at: www.jonesenergy.com.

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Forward-Looking Statements

This press release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this press release that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this press release specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including guidance regarding the number of rigs we intend to operate, the initial 2018 capital budget, reductions in Merge wet gas fees as a result of new contracts, fluctuations in production, estimated timing of peak rates, expectations regarding the number of gross and net wells to be drilled, and projections regarding total production, average daily production, percentage liquids, operating expenses, production and ad valorem taxes as a percentage of revenue, cash G&A expenses and capital expenditure levels for 2018. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current economic and market conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include, but are not limited to, changes in oil and natural gas prices, weather and environmental conditions, the timing and amount of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as the Company's ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting the Company's business and other important factors that could cause actual results to differ materially from those projected as described in the Company's reports filed with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made and the

Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Reconciliation of PV-10 to Standardized Measure

SEC PV-10 and NYMEX PV-10 are considered non-GAAP financial measures. SEC PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. SEC PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. SEC PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of SEC PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil, NGL and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil, NGL and natural gas properties. SEC PV-10, however, is not equal to, or a substitute for, the standardized measure of discounted future net cash flows. Our SEC PV-10 measure and the standardized measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

NYMEX PV-10 as disclosed in this release differs from SEC PV-10 due to the oil and natural gas prices utilized in the determination of future net cash flows and other factors including, but not limited to, regional differentials in pricing that vary from SEC pricing. We believe that NYMEX PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows based on the current commodity price environment.

The following table provides a reconciliation of the components of the standardized measure of discounted future net cash flows to SEC PV-10 at December 31, 2017, 2016 and 2015 and NYMEX PV-10 at December 31, 2017 assuming strip pricing as of January 2, 2018 through 2023 and keeping pricing flat thereafter.

(in millions of dollars)	As of December 31,	
	2017	2016
Standardized measure	\$ 567	\$ 383
Present value of future income taxes discounted at 10%	60	18
SEC PV-10	\$ 627	\$ 401
Change in pricing assumptions from NYMEX to SEC and other	94	
NYMEX PV-10	\$ 721	

Reserve Categories

Under SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Cawley, Gillespie & Associates, Inc., our independent petroleum engineers, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to

producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and well completion using similar techniques.

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