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Contango Announces Fourth Quarter 2017 Production, Year-End Reserves, Operations Update and 2018 Capital Strategy

HOUSTON, March 05, 2018 (GLOBE NEWSWIRE) -- Contango Oil & Gas Company (NYSE MKT:MCF) ("Contango") announced today production for the fourth quarter of 2017, reserves for the year-ended December 31, 2017, an operational update and its capital strategy for 2018.

Fourth Quarter 2017 Summary

- Estimated production of approximately 4.8 Bcfe for the quarter (51.8 Mmcfed; 32% liquids); within guidance, despite late December weather related shut-ins
- Brought one Southern Delaware Basin well on production while spudding two additional wells. So far in 2018 we have completed one well, are completing another well, and have spud and reached total depth on another well.
- 25% increase in year-end reserves, an increase of 37.5 Bcfe
- 55% increase in SEC PV-10 value of year-end reserves, an increase of $91.1 million
- Increased commodity price hedge protection to approximately 28% of forecasted PDP gas production and 69% of forecasted PDP oil production for 2018, and to 38% of forecasted PDP oil production for 2019

Management Commentary

Allan D. Keel, the Company's President and Chief Executive Officer, said "We continued to make great progress toward developing our Southern Delaware Basin acreage position during the quarter, and have budgeted approximately $52 million to continue developing the area in 2018 through a one rig program. We will continue to monitor our results, commodity prices and service costs, and make appropriate adjustments to our drilling program as we go along. We are also in the process of rationalizing some of our non-core assets as a means to providing additional capital for the further development of our Delaware position.

Fourth Quarter Production

Estimated production for the quarter ended December 31, 2017 was approximately 4.8 Bcfe, or 51.8 Mmcfed, within our previous guidance of 50 - 55 Mmcfed. Current quarter production was less than the 5.9 Bcfe, or 64.3 Mmcfed, for the same period last year due to adding only five new producing wells to production since the initiation of our drilling program in the Southern Delaware Basin beginning in late 2016. We also experienced cold weather shut-ins in some of our South and West Texas properties during the month of December. Production for the quarter was approximately 68% natural gas and 32% oil and natural gas liquids compared to the prior year quarter of 71% natural gas and 29% crude oil and natural gas liquids. Natural gas production for the quarter was preliminarily estimated at approximately 35.4 Mmcfed compared to 45.8 Mmcfed for the prior year quarter, and crude oil and natural gas liquids production during the current period was preliminarily estimated at 1,400 and 1,300 barrels per day, respectively, compared to 1,380 and 1,700 barrels per day, respectively for the same quarter last year. Production for the first quarter of 2018 is estimated to remain between 50 and 55 Mmcfed, though we expect to commence production on two new wells in March and April.

Year-end 2017 Proved Reserves

As of December 31, 2017, our independent third-party engineering firms estimated our proved oil and natural gas reserves to be approximately 189.3 Bcfe compared with 151.8 Bcfe of proved reserves as of December 31, 2016, an increase attributable to the success of our Southern Delaware Basin drilling program and the impact of the increase in commodity prices on the volume and value of our proved reserves. The success of our oil-weighted drilling program in the Southern Delaware is also reflected in the more balanced commodity profile of our reserve base at year-end 2017. At the end of 2017, the composition of our proved reserves, volumetrically, was 48% natural gas, 34% oil and condensate and 18% natural gas liquids, compared to 69% natural gas, 14% oil and condensate and 17% natural gas liquids at December 31, 2016. These estimates were prepared in accordance with reserve reporting guidelines mandated by the Securities and

Exchange Commission ("SEC").

As of December 31, 2017, the SEC PV-10 value of our proved reserves was approximately $257.3 million, compared to the SEC PV-10 value of $166.2 million as of December 31, 2016, an increase in our reserve value that was also attributable to our Southern Delaware Basin drilling program and the increase in commodity prices. The SEC-mandated prices used in determining our December 31, 2017 proved reserves and PV-10 value were $47.41 per barrel of oil and condensate, $2.92 per Mmbtu of natural gas and $18.59 per barrel of natural gas liquids, compared with SEC prices of $38.67/Bbl for oil and condensate, $2.43/Mmbtu for natural gas and $13.62/Bbl for natural gas liquids used in estimating proved reserves as of December 31, 2016.

Our proved developed reserves for the year ended December 31, 2017 were estimated at 123.9 Bcfe, compared to 129.4 Bcfe in the prior year. The slight decline in proved developed reserves can be attributed to approximately 20.1 Bcfe of production during the year and 3.1 Bcfe in property sales and performance revisions, partially offset by 17.8 Bcfe in extensions and new discoveries.

Our proved undeveloped reserves ("PUD") for the year ended December 31, 2017 were 65.4 Bcfe, compared to 22.4 Bcfe at December 31, 2016. The increase in PUD reserves can be attributed to 52.3 Bcfe in extensions and new discoveries, primarily in the Southern Delaware Basin, and 2.9 Bcfe in positive revisions, partially offset by the reclassification of 12.2 Bcfe to unproved reserves as a result of the failure to drill those PUDs within five years of the initial booking as proved, as required by the SEC's five-year rule.

The above estimates do not include net proved reserves of approximately 30.7 Bcfe and 32.6 Bcfe attributable to our 37% equity ownership interest in Exaro Energy III LLC ("Exaro") as of December 31, 2017 and 2016, respectively. The PV-10 value of the proved reserves attributable to our 37% interest in Exaro was approximately $24.4 million and $19.8 million at December 31, 2017 and 2016, respectively.

Southern Delaware Basin Drilling Activity

Crusader #1H

In mid-December 2017, we brought the Crusader #1H well on production, which was completed in the Lower Wolfcamp A. This well was drilled to a total measured depth ("TMD") of 20,275 feet, including a 10,184 foot lateral, and was completed with 50 stages of fracture stimulation. Our initial 24-hour max IP rate was 695 Boed (81% oil) with a 30-day average IP of 389 Boed (67% oil), low compared to the 1,187 average initial 24-hour max IP rate and 968 Boed average 30-day IP for our first four wells. The Crusader was the first well where we ran tubing and gas lift valves prior to initial flowback. We use an annular gas lift design that enables the well to achieve rates equivalent to that achieved with ESP pumps, but at much lower costs. Prior wells were initially flowed up casing until they died at which time tubing and gas lift valves were run. Running tubing up front prevents the wells from having to be shut-in for the seven to ten days required to run the tubing. We are monitoring the Crusader decline profile to determine if there is a benefit to reducing the flowback rate.

Ragin Bull #3H

The Ragin Bull #3H, targeting the Lower Wolfcamp A, was spud in November 2017. This well was drilled to a TMD of 20,570 feet, including a 10,325 foot lateral, and was completed with 50 stages of fracture stimulation. Flowback began in late January 2018, at an initial 24-hour max IP rate of 1,240 Boed (68% oil), and it appears that it will have a 30-day average of greater than 1,000 Boed. Proppant was reduced from 2,500 to 2,250 lbs per ft. of lateral and the frac fluid was reduced from 80 to 60 barrels per ft. of lateral on the Crusader and Ragin Bull wells in order to reduce overall completion costs. We ran tubing and gas lift valves prior to initial flowback and were able to significantly improve the initial flowback rates compared to our first attempt on the Crusader. Performance on the Ragin Bull #3H is consistent with our best well in the play to date. With the cost gains from our drilling efficiencies and the reduction in frac requirements, we feel that we will see significant increases in IRR and present value of the wells.

River Rattler #1H

The River Rattler #1H, our first Wolfcamp B test, was spud in December 2017. This well was drilled to a TMD of 20,710 feet, including a 10,275 foot lateral, and is currently being completed with a planned 50 stage fracture stimulation. We expect to bring this well on line in mid-March 2018.

Ragin Bull #2H

The Ragin Bull #2H, our second Wolfcamp B test, was spud in January 2018 and has reached total depth of 20,624 feet, including a 10,344 foot lateral. This well represents our fastest spud to total depth so far at 26.5 days. A 50 stage frac is scheduled in mid-March. There have been multiple Wolfcamp B wells drilled adjacent to our leasehold that have been put on line recently by our offset operators. The early results of these tests appear very encouraging.

Gunner #3H/Sidewinder #1H

The rig will next move to the Gunner/Sidewinder location to drill two wells from a common pad. The Gunner well will be a Wolfcamp B test in the same unit as the Gunner #2H Wolfcamp A completion. That completion is our best well to date having produced approximately 130 MBOe in 6 months. The Sidewinder well will be a Wolfcamp A test just south of the Rude Ram #1H Wolfcamp A completion which has produced 155 MBOe in 9 months. Both wells from this pad will have approximately 10,000' laterals and will be zipper fraced in June 2018.

Other Drilling

CML Beeler Ranch #1H

The CML Beeler Ranch #1H, our initial participation in a Georgetown test, was spud in the fourth quarter 2017 and came on line in January 2018. The well is located in our Zavala/Dimmit County leasehold in South Texas and is a dual lateral with each lateral comprising approximately 10,000 feet of open hole completion within the Georgetown formation which underlies the Buda and Eagle Ford. The completion resulted in an initial 24-hour max IP rate of 1,164 Boed (87% oil) and a 30-day average IP of 850 Boed (91% oil). Contango has an approximate 17% WI in this well. Completed well costs are estimated at $3.4 million, gross. Additional wells are being planned in 2018 by the operator which could include our acreage and participation.

2018 Drilling Program and Capital Budget

As a result of the success of our 2017 drilling program in the Southern Delaware Basin, we have budgeted to invest approximately $52 million to develop in that area during 2018. Our drilling program is well underway having reached total depth on two wells in 2018. Our preliminary budget calls for us to spud eight to nine wells, while also completing eight to nine wells (including one well, the River Rattler #1H, that was spud in December 2017). We expect our program to continue to show improvement in our drilling results, as we have seen in the last 3 wells averaging 27 days spud to total depth. We will continue to test the multiple benches within the 2,500 feet of objective section in the Bone Springs and Wolfcamp. Completions will still be approximately 10,000' laterals and will involve 2,250 to 2,500 pounds per lateral foot of proppant. We currently have planned four Wolfcamp A wells, two Wolfcamp B wells, and three Bone Springs wells to be spud in 2018. We will continue to monitor commodity prices and service/supply costs during the year, and if deemed appropriate, may make adjustments to our drilling strategy for the remainder of the year. Additional capital may be allocated to the Georgetown development mentioned above.

Liquidity

Long-term debt at December 31, 2017 was approximately $85.4 million, all under our revolving credit facility, compared to $54.4 million at year-end 2016. Our credit facility currently provides for a borrowing base of $115 million through May 1, 2018. We currently anticipate that we will fund our 2018 program with internally generated cash flow, proceeds from the sale of certain non-core onshore assets and temporary borrowings under our revolving credit facility. We will continue to investigate ways of prudently increasing the availability of drilling capital during 2018, with the goal of potentially bringing in a second rig for our Southern Delaware program.

Derivative Instruments

As commodity prices have begun to rise, we took advantage of that strength in the price environment to add additional minimum price protection for our forecasted monthly production volumes and have the following hedges in place for 2018 and 2019:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Natural Gas	Jan - July 2018	Swap	370,000 MMbtu	$3.07 (1)
	Aug - Oct 2018	Swap	70,000 MMbtu	$3.07 (1)
	Nov - Dec 2018	Swap	320,000 MMbtu	$3.07 (1)
Crude Oil	Jan - Jun 2018	Swap	20,000 Bbls	$56.40 (2)
	Jul - Oct 2018	Collar	20,000 Bbls	$52.00 x $56.85 (2)
	Nov - Dec 2018	Collar	15,000 Bbls	$52.00 x $56.85 (2)

	Jan - Dec 2018	Collar	2,000 Bbls	$52.00 x $58.76 (3)
	Jan - Jul 2018	Collar	6,000 Bbls	$58.00 x $68.00 (2)
	Nov - Dec 2018	Collar	5,000 Bbls	$58.00 x $68.00 (2)
	Jan - Dec 2019	Collar	7,000 Bbls	$50.00 x $58.00 (2)
	Jan - Dec 2019	Collar	4,000 Bbls	$52.00 x $59.45 (3)

1. Based on Henry Hub NYMEX natural gas prices.
2. Based on Argus LLS NYMEX crude oil prices.
3. Based on WTI NYMEX crude oil prices.

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