Natural Gas Market Indicators

American Gas Association

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Reported Prices – oil and natural gas commodity pricing as measured by the forward NYMEX trading metrics continue to rattle between $44 to $50 for WTI and Brent crude and are under $3 per MMBtu for natural gas. Uncertainty and weak weather-driven, short-term market expectations compared to recent years appear to be influencing reported exploration and production drilling decisions by producers – primarily that less is more in today's pricing climate – less costs, less capital expenditures, and perhaps eventually a lower rate of oil and gas production.

Weather – five straight weeks of warmer than normal temperatures for the nation as a whole were followed by three straight weeks of colder conditions in January, leaving the cumulative tally of heating degree days 3.2 percent lower (warmer than normal) for the period October 1, 2014 through January 17, 2015. Then temperatures warmed up again and the cumulative total rose to 4.6 percent warmer. Coldest temperatures this winter heating season have been concentrated in the east north central as well as the east and west south central portions of the country. The warmest region compared to normal has been the Pacific area, which has been 26.8 percent warmer than normal since early October.

Working Gas in Underground Storage – more than 450 Bcf of natural gas was cumulatively withdrawn from underground storage (452 Bcf) for the two weeks ending January 9 and 16, 2015 yet even that volume of working gas activity left inventories 8.2 percent ahead of last year at 2,637 Bcf and only 5.5 percent behind the five-year average. Working gas dropped another 94 Bcf for the week ending January 23 – less than half as much compared to last year. Going back to November 2014, the two recent 200+ Bcf drawdowns were only the third and fourth triple digit pulls for the winter heating season to date and the first to be over 200 Bcf.

Natural Gas Production – domestic dry natural gas production has continued to firm after moving up and down between 70 and 73 Bcf per day with the influences of bitter cold in some parts of the country in recent weeks. Even with the temporary impact to production from ice storms and such in January 2015, production is running 6.7 Bcf higher than that in January 2014.

Shale Gas – in today's economic environment gas producers may have a market incentive to pullback, reduce costs, and manage drilling investment decisions very closely. That can't be a surprise. That does not mean, however, that shale-directed drilling, midstream projects and infrastructure builds just stop. How quickly the new market discovers an equilibrium will be a question contemplated and commented on by analysts for weeks and months to come. Interestingly, Wood Mackenzie in a several January news releases anticipates overall drilling and completion *cost* declines of about 15 percent relative to 2014 -- some companies reaching as high as 40 percent reductions – if oil averages around $50 per barrel during the year. This has an effect of lowering production costs in dry gas plays as well. The same research notes suggest that Haynesville break evens have declined to the low-to-mid $3 per MMBtu range. Even so, Wood Mackenzie anticipates the number of oil and gas wells drilled and completed in 2015 may fall as much as 10,000 wells from about 37,000 in 2014 to 27,000 in 2015.

Rig Counts – oil and gas rig counts took another plunge for the week ending January 16, 2015 with a drop of 74 units operating – 55 down on the oil side and 19 down on the gas-directed operations. He following week also saw a drop. Total rigs at 1,633 are now 144 *below* the count for the same week in 2014. This marks 7 straight weeks of decline in the oil rig count with gas-directed drilling bouncing up and down. That said, gas drilling at 316 rigs was in the same range during mid-June and before that April of 2014 but hasn't been below 300 since May of 1993 – almost 22 years ago. Part of the story today is drilling efficiency (fewer rigs needed to produce more gas) but also market dynamics play a role in drilling investment decisions and that is being played out today. In the same Wood Mackenzie news release referenced earlier, analysts estimate that an oil price average around $50 per barrel in 2015 may cause a 40 percent decline in horizontal rig counts compared to horizontal operations in 2014.

Pipeline Imports and Exports – pipeline volumes from Canada have hovered around the 6.0 Bcf per day mark during the past week with average flows of 6.5 Bcf per day so far this January, about 0.2 Bcf per day less than this time last year. Pipeline flows exported to Mexico are conversely up, having averaged 2.1 Bcf per day this month, a gain of 0.4 Bcf per day year over year.

LNG Markets – the nineteenth proposed LNG export project in Canada was recently confirmed by ExxonMobil and is to be located on the west coast in British Columbia at Tuck Inlet within the city limits of Prince Rupert. The project may cost as much as C$25 billion and would initially demonstrate a capacity for export of 2 Bcf per day and be expandable to twice that volume. None of the current projects on the books for western Canada has made a final investment decision but several are in a more advanced stage of planning. LNG volumes placed into the US pipeline grid averaged 0.6 Bcf per day for the month of January – 0.4 Bcf per day more than in January 2014.

Natural Gas Market Summary – the idea of structural versus price-induced demand growth is playing itself out in the power generation market for natural gas this winter. Natural gas power burn has consistently pointed to increased volumes to start the first quarter of 2015 compared to 2014, at least in part due to lower natural gas acquisition prices, and as a result power demand has averaged 22.9 Bcf per day, 1.2 Bcf per day more than last January, which at the time was a record for a winter heating season month. When Henry Hub prices go below $4.00 per MMBtu and certainly below $3.50 per MMBtu this same scenario seems to play out in the natural gas market. That said, one cannot help but wonder with overt and subtle shifts in the power generation fleet for economic and environmental reasons across the country how much of any of these demand events actually gets structurally built into more normal gas demand and ultimately becomes less price sensitive.