Are Natural Gas Reserves Now Overstated?

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The future of natural gas production is a puzzle. There have been stories about the potential of unconventional natural gas, and natural gas reserves reported by companies have been increasing. Production by companies has risen to the point where there is a supply glut, and there has been a cutback in drilling. Recently, Robert Rapier had a post called How Much Natural Gas Do We Have to Replace Gasoline?.

But Arthur Berman, a contributing editor and columnist for *World Oil* magazine, says some caution is in order. This past week, he wrote an article for ASPO-USA called Lessons from Barnett Shale Suggest Caution in Other Shale Plays.

Mr. Berman thinks that public companies are way too optimistic in their natural gas reserves, both in the Barnett Shale, and in other shale plays, such as the Haynesville and Marcellus shales. These companies may also be making bad decisions about drilling if they are over-estimating how much gas they can produce from a given well.

I think Mr. Berman's cautions are probably worth thinking about, so have paraphrased what he said, and added some thoughts of my own at the end. The two issues I see are

1. Does extensive fracing move natural gas production forward, so that past patterns, and estimates of reserve life, produce much too high estimates of the volume yet to be extracted? and

2. Are historical decline patterns for tight gas (produced using vertical wells without much fracing) misleadingly good for shale gas with fracing?

The original article is linked above. If you are at all technically inclined, I suggest reading it as well.

Why does Mr. Berman think caution is in order?

Mr. Berman says he examined the experience of the Barnett Shale, based on IHS data, and came to the following conclusions:

• Most reserve predictions based on hyperbolic production decline methods were too optimistic when compared with production performance.

• There is little correlation between initial production rates and ultimately recoverable reserves.

• Average well life is much shorter than predicted.

• The volume of the commercially recoverable resource has been greatly over-estimated.

• Core areas of the play do not have appreciably higher average ultimately recoverable reserves than the play overall.

• The ultimately recoverable reserves from horizontal wells is not significantly greater than from vertical wells.

• Average well performance has decreased consistently since 2003 for horizontal wells.

What are the underlying problems? According to Berman, he sees the following problems:

1. Group curve fitting is misleading. It is easy to think that a hyperbolic decline rate will be predictive of future production. But with all of the fracing, it just doesn't work that way. According to Berman, wells suddenly lose pressure and production drops below what the fitted curve would predict. This can happen anytime between 12 months and 5 years. More fracing doesn't get production back up to the prior curve.

2. Initial production rates aren't very predictive of total production. While high initial production is helpful, what one really needs is a decline rate that isn't too steep. About half of production is in year one.

3. Economic life is of wells is much shorter than expected. Berman reports that operators expect a well life of 30 to 40 years, but in practice, the most common economic life (mode) is only 4 years. He quotes an average life of 7.5 years, and a maximum of 15 years.

4. Horizontal wells are not living up to expectations. Berman indicates that owners are predicting recoveries of 2.5 billion cubic feet per horizontal well, but Berman's estimate is that ultimate recoveries will be about a third of that or .81 billion cubic feet. According to his calculations, horizontal wells produce only 31% more than vertical wells, but cost 2.5 times as much.

5. Terminal decline rates are 15% per year, not 4% to 8%. Berman estimates a much higher decline rate than most operators are using. Also, once production drops below operating costs, it doesn't make financial sense to keep the well open.

6. Lack of improved production per well with improved technology. Berman had expected to see improvement in production per well with improved technology, but instead, Berman's estimate of economic recovery for horizontal wells has dropped from 1.14 per billion cubic feet per well in 2003 to .59 per billion cubic feet per well in 2008.

Berman feels that the USGS technically recoverable gas estimates for Barnett Shale are likely way to high, even though many companies believe the opposite. The USGS estimates total technically recoverable resources of 26 trillion cubic feet in Barnett Shale. Berman estimates that the 11,817 wells drilled to date will only produce about a third of this amount, or 8.8 trillion cubic feet. If this is all that has been drilled to date, Berman estimates that the remaining 23,000 wells will cost over $75 billion dollars, just for the initial work (leasing, drilling and completion costs). According to my calculation, this amounts to $4.36 per thousand cubic feet--more than natural gas is currently selling for, without considering costs for the remainder of the supposed 40 year lifetime.

My Thoughts

I am certainly no expert in this area. I did visit BP's Tight Shale Gas Facility in Wamsutter, Wyoming in 2008. BP's facility is tight gas, not shale gas. Since tight gas facilities have been in operation a long time, and shale gas is quite new, BP's tight gas facility is likely similar to what the new shale mines are trying to model their experience after.

BP's site used only vertical wells. BP was planning on a 30 year, or possibility 40 year, lifetime for their wells. BP has been operating in the area since the mid 70s, so has experience with tight gas wells that have been producing for almost 40 years. Their operation was set up to minimize servicing costs on a large number of wells that have been producing for many years.

I don't know exactly how much fracing BP has been doing on their wells, but I am sure historically it was not anywhere near the level that is being done now. BP mentioned recent changes which had improved productivity, and that likely included fracing. Of course, the question then becomes: Does fracing really increase total production, or does it just move it forward in time, or is it a combination of the two?

In my work as an actuary, quite a bit of my work involves forecasting future claim payouts based on historical claim experience. In many ways, it has a lot in common with what is being done in reserve estimations for these natural gas wells. Insurance coverage often have very long claim payout periods, and one doesn't always have comparable data to look at, so one has to work around the lack of comparable data. The estimates an actuary makes have a big impact on both reserves and on decisions as to what products are profitable to sell in the future.

I can easily understand how someone could jump to the conclusion that if fracing makes recoveries during early production higher, it would lead to close-to-proportionately higher production over the life of the well. I can also understand substituting tight gas experience for shale gas experience, if there is no long term historical experience for shale gas. One might also substitute vertical well experience for horizontal well experience if inadequate long-term horizontal well experience exists.

I can also imagine gas companies not looking too closely at industry experience regarding decline rates. After all, this takes quite a bit of time, analysis skills, and access to the IHS data base to do this. If gas companies are small, and have limited staff, they are likely not set up to do this.

My experience with auditors is that they aren't many steps ahead of the company people. Each auditing firm is likely looking at the reserves of several different natural gas producers. If they are all making the same assumptions, the auditor feels pretty certain that what they are doing is right--or at least consistent with what other companies are doing. The auditing firms check for computational errors, but are not likely to think about whether the decline rate assumptions are wrong (unless someone points out the issue to them.)

Nearly all the players would like things to look good--the USGS, companies setting reserves, the people selling the fracing materials, and investors. Except for Arthur Berman, it isn't clear that there are too many people looking at aggregate decline rates on shale gas deposits. One might think that consulting firms would look at this--for example Cambridge Energy Research Associates (CERA) or Navigant Consulting or Advanced Resources International, but unless someone pays them for this service, it likely won't get done.

Once companies have gone down the wrong road in making estimates, it is my experience that it is awfully hard to turn around. The financial implications get to be huge. It is hard for an auditing firm (or firm selling ongoing consulting services) to do more than nudge the estimated decline rates a bit in the right direction, and hope that things will get better over time.

I would hope that other people will start looking closely at the questions Arthur Berman is raising. Does IHS data really indicate that shale decline rates are a lot worse than companies are forecasting? What are reasonable lower bounds at which production becomes non-economic? Are natural gas companies really being over-optimistic on the long-term benefit of fracing? Have natural gas reserves been raised too much? Could there even be a problem even on tight gas reserves, if fracing moves production forward, and reduces what is producible in the later years?