Discovery Capital L.L.C

Providing Integrated Solutions For the Energy Industry

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Do I Have Enough Gas to Lay a Pipeline?

In my practice I am often asked to evaluate the viability of laying a gas pipeline to tie in a new well. Recently I evaluated two wells that were between 7-10 miles from an existing sales line. Obviously a considerable expense was involved in laying the pipe. We did not want to lay the pipe without some assurance that the investment would be recouped, with a return. So how do we determine if the risk is worth the return.

The first thing we have to realize is that there is a risk component to any reserve evaluation. All of this stuff is going on a mile underground and we cannot see, taste, touch or hear any of it. Our job is to quantify and minimize that risk. How do we do this? A long-term production test is the best way.

From a long-term test we may deduce some or all of the following parameters:

- Reservoir Permeability
- Permeability Barriers, restrictions and Reservoir Geometry
- Long term Production Rates
- Effect of Compression on the Producing Rate
- Skin Damage
- Effect of Fracing
- ***Minimum*** Reserves in Place

Because most of us are in the business of making money, **not** finding Oil and Gas, the item of most interest is the Long Term Production Rate. This is what pays the bills. Short-term tests are good for short-term projections, Long-term tests are good for longer term projections. Like most things in life there is no free lunch. If you want good data it is going to cost you more.

So why does a long-term test cost more you may ask? There are two variable costs involved in a well test, produced gas and tool rental. During a test the well may need to be vented for a week. It is common to vent 10MMcf of gas to the atmosphere during a test. At $3/mcf that is about $30,000 worth of gas gone up in smoke. For a tight gas zone it is common to run a 3-week shutin, at a tool cost ranging from $3,000 - $10,000, depending on the number of recorders in the hole. The number of recorders is dependent on how lucky you feel. I will talk more about this later.

Now that we have all of the disclaimers out of the way, how do we design an extended test. Strangely enough, the first piece of data I need is the cost to lay the pipeline. This cost is the basis for how big an area needs to be tested, or more accurately how much gas needs to be removed form the formation.

Ok, now lets get practical about this and throw out some concrete examples. Let's say that the well in question is located about 6 miles from the desired connection. In this area the operator estimates that it will cost about $50,000/mile to build the pipeline, or $300,000 total cost to get the gas to market. When we test this well we want to make sure that we can recoup the $300,000 including a return and we also want to account for some risk.

What about recouping the drilling and completion costs you may ask? Sorry you are out of luck on those. They are "sunk costs" nothing you do from this point forward should be dependent on what you have already spent. You are making decisions only on incremental dollars to be spent. Taking all the above into account and stirring it up with various rules of thumb, I come up with a total exposure of $600,000. I want to prove that I can recover this amount in "unrisked" reserves before I spend another buck. Your results may vary depending on how you view the situation. If for instance you have an override or access to OPM you may have a substantially lower hurdle rate.

We have now agreed that we need $600,000 worth of gas in the ground before we start construction. When we look into our crystal ball (NYMEX Futures) we see that gas prices over the next 24 months will average $3.50/mmbtu. Let's remove some cost for gathering, compression and royalty etc. and we come up with a net of about $3/mcf (just to make the math easy for you geologists). At $3/mcf this calculates out to about 200MMcf of producible gas.

Where to from here? This is where it gets a little tricky. The tools we use to measure pressure are accurate to 0.5% of the maximum recorded pressure. The manufacturers spec sheets show better than this, but if we believe everything manufacturers tell us, then we have more pressing problems than laying a pipeline. Let's assume that the P_i (Initial Reservoir Pressure you remember this from the last newsletter) is 2000 psi. That means that if the pressure drop recorded by the tool is less than 10 psi (.005*2000 psi), we don't know if the pressure drop is real or if it is simply tool error.

Let's use some numbers. P_i = 2000 and the extrapolated pressure at the end of the test P* (check the last newsletter) =1992 psi. Because the pressure drop is only 8 psi we don't know if the reservoir pressure really dropped by that amount, because of the inherent inaccuracy of the tool, or not. If on the other hand, P*=1980 psi we can be pretty sure that we saw some real depletion in the reservoir.

With this concept firmly in mind, it becomes obvious that we must remove more than 0.5% of the targeted gas in place in order to have any confidence in the outcome. So in this case I would decree that we need to produce at least 1MMcf (.005*200MMcf) during the test. Understand that this is the minimum volume needed in order to confirm the hurdle rate. I would tend to recommend that even more be produced.

Now that we know how much needs to be produced, how fast should it be taken out. Typically the well helps out here. If the well will only give up 100 mcfd then we leave it on long enough to get the total volume. If on the other hand the deliverability is 2,000 mcfd you can get the flow period over with very soon. ***The quality of test is not dependent on the flow rate.*** The data is considered better if the flow rate is constant throughout the test, but corrections are available to account for changes in flowrate.

It is very common on a tight gas well to have to adjust the choke during the test to account for the drop in rate. By the end of one recent test we had to open the choke all the way in order to get the flowrate to the desired point. It is important to record all of the rates and pressures during this phase of the test. A digital surface recording meter/gauge is the best method, even if it does cost more.

The final portion of the design phase is determining how long to shut the well in. This is certainly the most subjective part of the test. Ideally the well should be shutin until it has built up to P*. Two problems here, first we don't know what P* is, and second we don't know if we reached it until we get out of the hole with the bomb. Too many variables not enough equations.

From a purely **theoretical** standpoint I generally use the DST from the zone as a starting point in determining the length of the shutin. Using my welltest analysis software I can construct a model based on the DST evaluation. After the model is constructed I can simulate different flowrates and different shutin times in order to optimize the test. Ideally I try to leave the well shutin until the Derivative curve shows a downward inflection. The inflection indicates a decided decrease in the rate of pressure buildup.

From a **practical** standpoint I do all of the theoretical stuff then monitor the wellhead pressure. After the first week of shutin I evaluate the data, looking particularly at the Derivative Curve. From this curve I can get an indication of what type of flow regime the well is in. If for instance the well has been in radial flow for quite a while I may decide that that I can shorten the test. If on the other hand I see an upwards deflection, I may want to leave the well shutin longer. If the wellhead pressure quits building during the scheduled shutin, I will probably recommend that the bomb be pulled.

How long should the bomb be left in the hole? **Until the client squeals about the cost.** The longer the better. The closer the well is to building up then the shorter the extrapolation. The shorter the extrapolation the more accurate it is. Not a lot of science in that statement, but it is the fact. It is the client's money being spent in both keeping the bomb in the hole and in constructing the pipeline so they need to be the final authority on the timing.

Listed below are a few items that must be accomplished in order to get a good test.

- **<u>Do not flow the well extensively on "clean up".</u>** The longer you clean the well up before the test, the longer the well must be shutin before the test start. The well will clean up during the flow portion of the test, there is no sense in wasting gas by flowing it twice. Make sure to record the gas volumes produced during clean up.

- **<u>Record static fluid level every 100'</u>** from the perfs up to where you estimate the fluid level may be.

- **<u>The bomb must be set directly across from the perfs.</u>** We are looking for such small pressure drops that setting the bomb as little as 10' above the perfs can introduce significant errors. Pay special attention to this if you are using a tubing conveyed gun. The bottomhole assembly can produce special clearance problems for the bomb.

- **<u>Record the static pressure across from the perfs for at least 30 minutes</u>**

- **<u>Flow the well with the bomb in the hole.</u>**

- **<u>Plan on using a Gas Pac if the flowrate is going to be over 1MMcfd, or if it is cold out.</u>**

- **<u>Run a static fluid gradient every 100' at the end of the test.</u>** How high to run this can be calculated by the difference between the tubing and casing pressure.

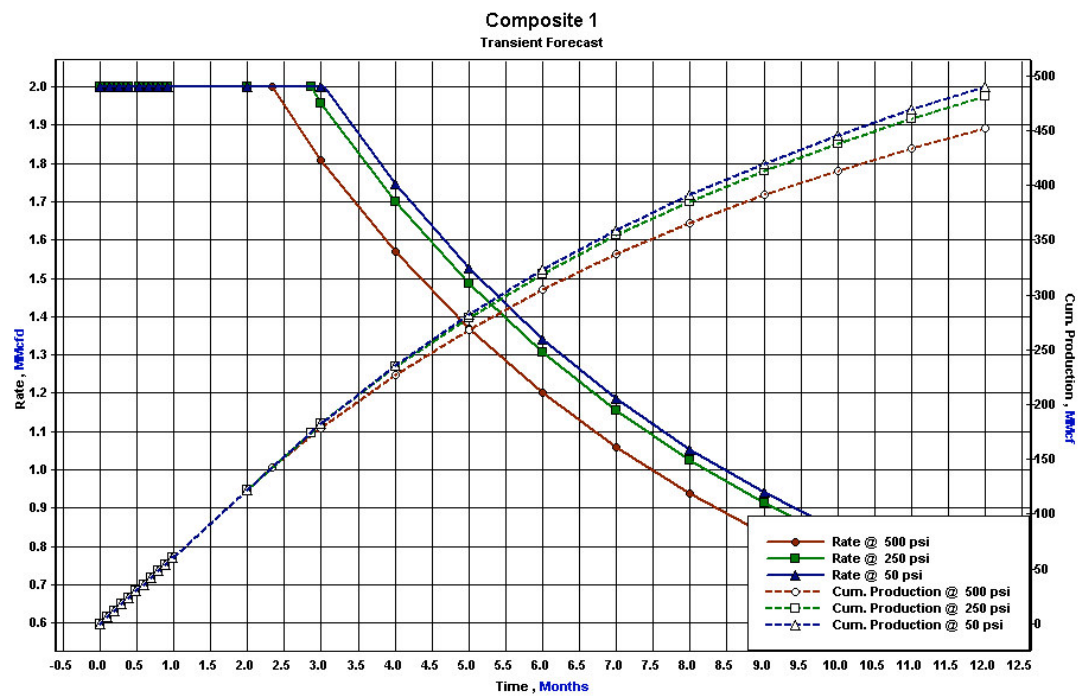
- **<u>Use a digital surface recorder.</u>** This is mandatory if you are only using one pressure recorder downhole. This is not only a backup but will allow me to more accurately determine when to pull the recorder.

- **<u>Use two pressure recorders downhole.</u>** You are going to feel awfully stupid if your only recorder dies.

Once the tool is out of the hole the analysis starts. The first step is to look at quality of the raw data. If two recorders are available I can display both data sets on the same screen and determine which set is better or cleaner. I can eliminate or average the data.

After the data has been scrubbed, I determine which flow model best represents the recorded data. I won't go into this here because it may be the subject of another newsletter, and this one is already too long. After modeling the past production and buildup I can use that model to forecast future production. I provide a report that itemizes all of the many parameters that go into the model and also provides a graphical forecast of future production.

Below is a sample plot containing a production forecast



In an effort to determine the sensitivity of the formation to backpressure, I have projected the production against three different pressures 500, 250 and 50 psi. Obviously the lowest curve is the highest backpressure and vice versa. In this case it appears that the well can flow an additional 200mcfd by lowering the pressure from 500 psi to 50 psi. Adding compression can lower the backpressure.

For many reasons that I won't get into here, long term projections are not reliable, especially for oil wells and small reservoirs. A significant pressure drop in the reservoir changes the PVT data for the fluids. For the purposes of evaluating the viability of a pipeline, the accuracy of this presentation is acceptable.

For longer-term projections a reservoir simulation is required. Guess what, I can do that too.

I have tried to touch on the highlights of this process. A long-term test can be a real money saver when critical (expensive) decisions need to be made. I recommend running them not only for pipeline decisions but also for development drilling, property purchases, bank reports and any time I have a car payment due.

If you have any interest in running a test or need more info, please call, or use the feedback form on my home page.

Bill