Discovery Capital L.L.C

Providing Integrated Solutions For the Energy Industry

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February Newsletter

How do I Know When to Drill a Development Well?

More than once when I have asked this question the same answer comes back – "Wherever a legal location exists." One time I had a young geologist propose a well in the middle of a somewhat depleted (500 psi measured bottom hole pressure) gas field. When I asked why he chose this location he proceeded to work through a volumetric analysis of the location. This was fine right up to the point when he referenced an author who said that the bottom hole pressure of a well in Kansas was about 0.465 psi/ft of depth. So when he plugged in this value into the volumetric equation, it came up with about a BCF of reserves.

I tried to explain how this was not the correct bottomhole pressure. He proceeded to explain that the author was a Ph.D. and asked how many books I had written. He was a good oil finder and I am sure that he now understands what I was talking about, but at the time he was insistent that because we had a legal location we needed to drill a well.

My experience has shown that here in Kansas many, if not most, fields are over-drilled. What is your criterion for drilling an infill well?

I recently worked on a project where one of the working interest owners wanted to drill a development well in a gas field and the others were unsure. They approached me and asked if a development well would prove up additional reserves or whether it would simply siphon off gas that the other wells would recover over time.

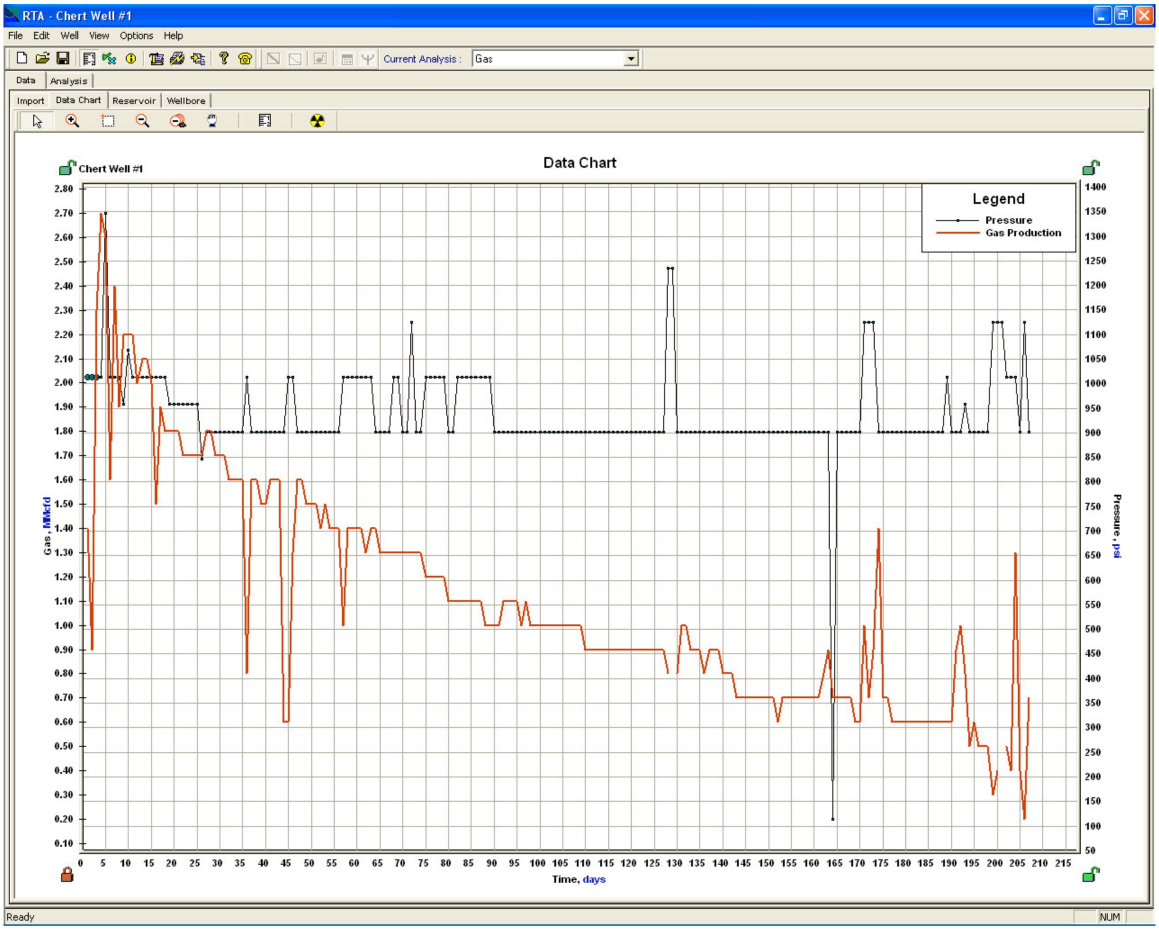
Three wells are currently producing in the field and the production is below what everyone involved had hoped. Some of the partners were concerned that the field was depleting, while others surmised that the reservoir was simply tight. The Formation is a Mississippian Chert in Kansas at about 4600'. Initial pressure was about 1510 psi.

Two proposals were made to estimate the reserves in place. The first was to shut the wells in for six days with a bomb in the hole. They proposed that the final pressure would be sufficient to make a P/z determination. The second idea was to use the recorded flowing pressures and rates to determine reserves in place.

My gut feeling was that this was a tight reservoir. I felt that the high initial rates seen earlier in the life of the first well was due to fractures, not high permeability. Seismic and a modern suite of logs provide the reservoir data such as S_w, porosity and net pay height.

CHERT WELL #1

Chert Well #1 was completed through perforations last summer and had an AOF of about 5.5 MMcfd. The chart on the following page shows the production history and casing pressures recorded since completion. The casing pressures have been corrected to bottom hole pressures.

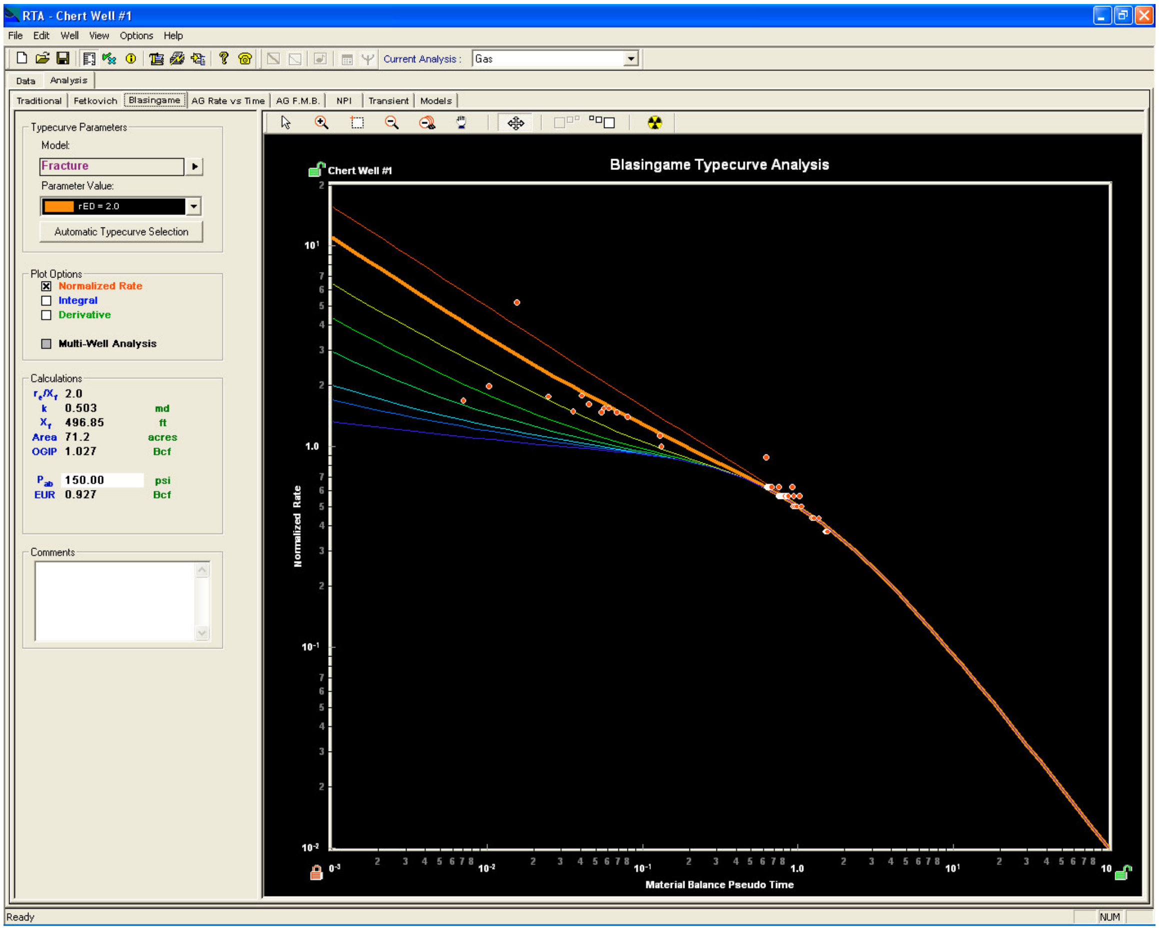


As you can see the flowing pressure was being maintained at about 900 psi at the wellface. This corresponds to a flowing tubing pressure of about 600 psi. The rate has dropped over a period of about 200 days from about 2.5 MMcfd to about 0.65 MMcfd. So the question is "depletion" or a tight reservoir. Standard Rate/Time, Rate/Cum or even Fetkovich Analysis will not answer this question.

A smart guy by the name of Blasingame with the help of slave labor (otherwise known as graduate students) came up with a method of combining flowing pressures and the Fetkovich curves. This combination yields a series of curves that can provide insight into a reservoir that is matched only by a numerical simulation.

When the rate and pressure data are manipulated and plotted on the Blasingame curves, two flow regimes become apparent. These are the "Transient" regime and the "Depletion" or "Pseudo Steady State" regime. The "Transient" regime means that the well has not seen the boundaries of the reservoir. The pressure is changing faster near the wellbore than at the reservoir limits. If all of the data points are in the transient regime, reserve determination is suspect. Depletion or Pseudo Steady State means that the well has produced long enough for the pressure to be governed by the reservoir boundaries. The pressure changes uniformly throughout the reservoir.

In its simplest interpretation, if the data plots are on the left-hand side of the curves then the well is still in the Transient regime. If however the points start showing up on the right-hand side then the well has seen the limits of the reservoir and Pseudo Steady State depletion is in process.



If you are familiar with the Fetkovich curves you will notice that there is only one depletion stem (right-hand side). This is another benefit of this technique vs. Fetkovich. The distinction between Transient and Depletion is where the multiple curves merge into one. Anything to the left is Transient while any points to the right represent depletion.

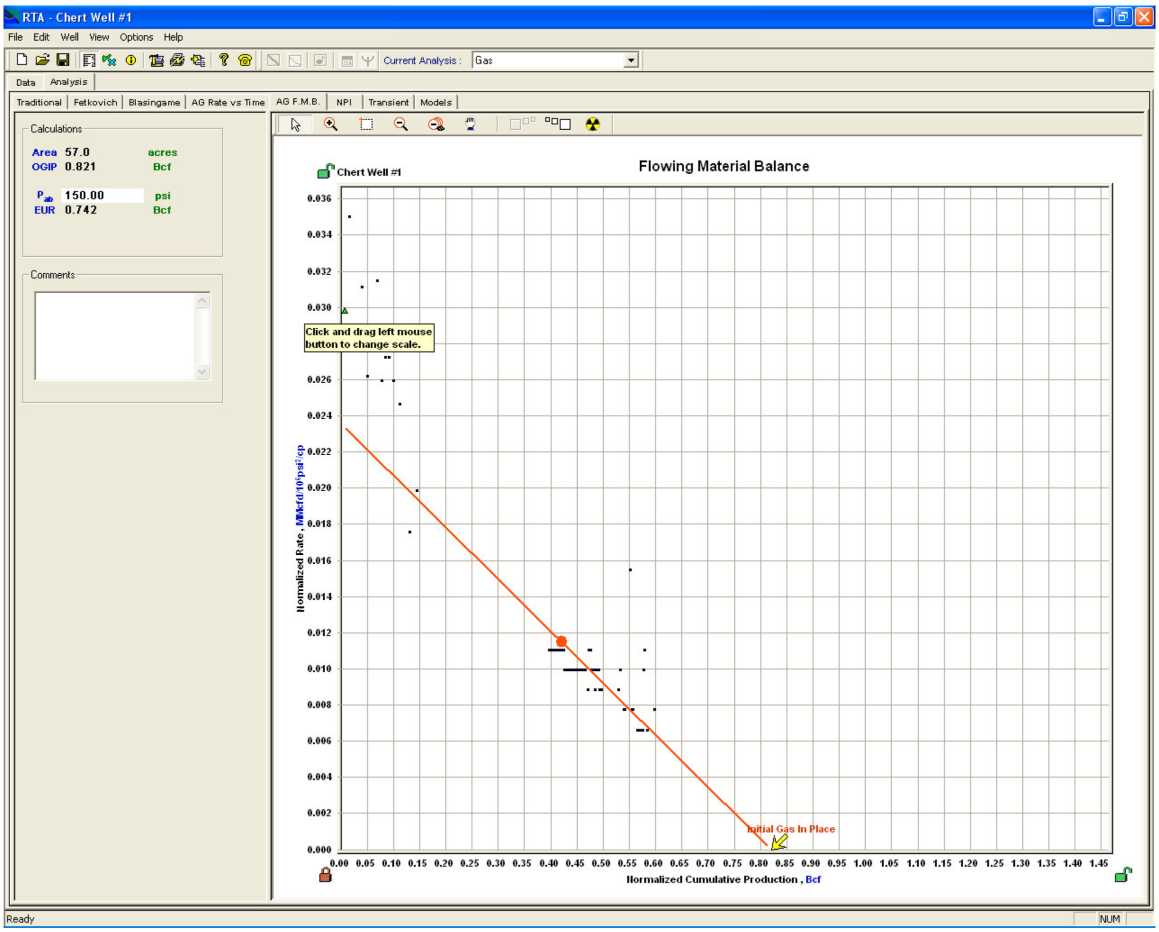
In this case it appears that the well is indeed producing from a limited reservoir. For those of you with old eyes the reservoir calculates out to be about 70 acres and had an OGIP of about 1 BCF. Also notice in the upper left-hand box that this is a “Fracture” evaluation. A Radial evaluation is also available but in this case it did not fit the data.

You can see that the data indicates a fracture half length, $x_{f,}$ of about 500’. The red curve has been highlighted as the best fit for this data set. This line defines the ratio between x_f and the reservoir radius, in this case the ratio is 2. This means that the reservoir has a radius of only about 1000’. Remember the area equation from high school, (3.14 x 1000$^{2)}$ /43,560 = 70 acres. The OGIP is calculated using this drainage radius and information from the logs.

Notice also that this method calculates permeability for the matrix. In this case it calculates to be about 0.5 md., very tight. No wonder the production is falling off like a leper’s arm.

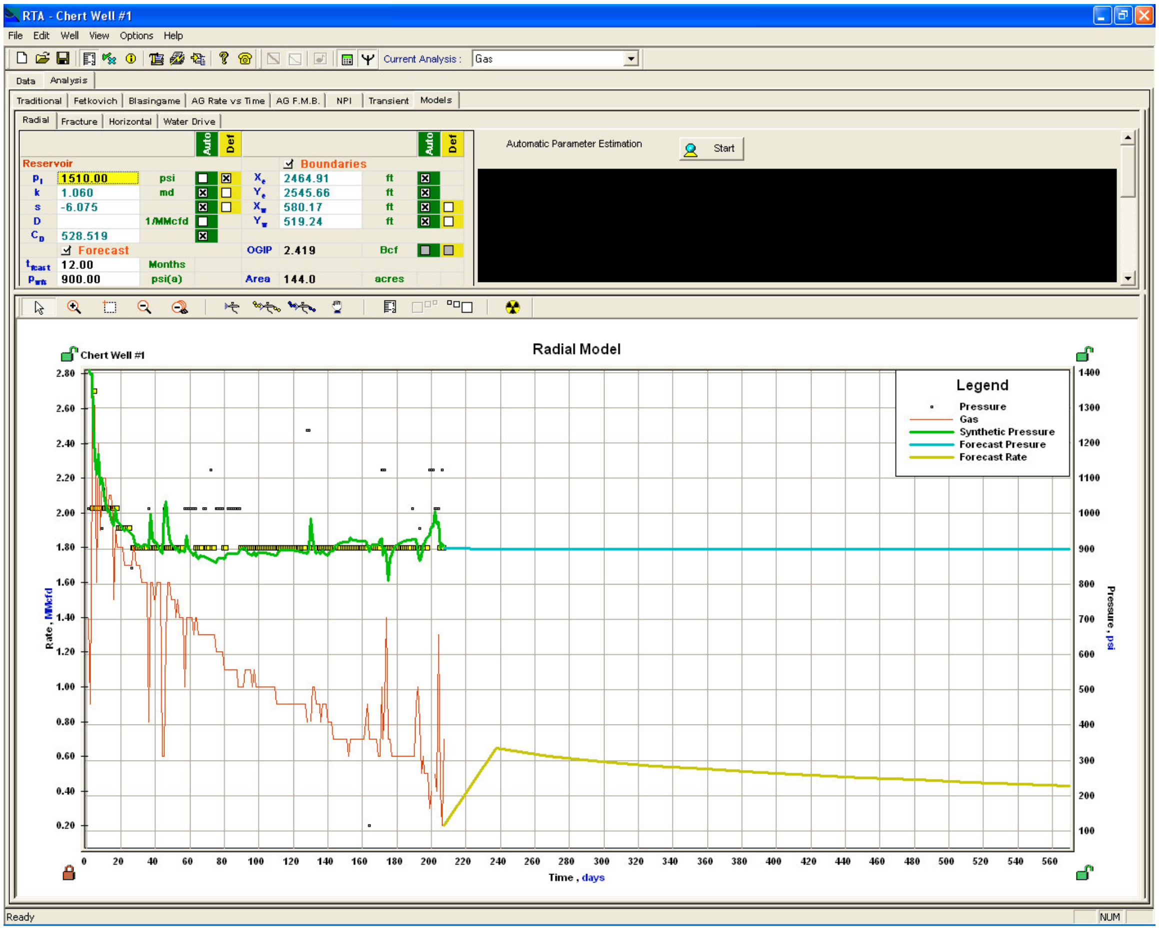
A couple of other smart guys named Agarwal and Gardner determined that if you manipulate the data enough, it is possible to construct what can be thought of as a “Flowing Material Balance” or “Flowing P/z”. Why is this so great you may ask? As I will show later on, it takes a shutin period of about 2 months or more for a well like this to build up to a point that P* can be extrapolated. Obviously no one wants to leave a well shut in for that period of time just to calculate reserves.

Enter the Flowing P/z. With this technique we are now able to calculate the reserves in place without shutting the well in. This can be done with accuracy that exceeds that of a shutin P/z. How can that be you ask? Most P/z data points are acquired due to state regulations that say the well only needs to be shutin for 24 hours. After 24 hours this well will only have built up to about 2/3 of it true reservoir pressure. If you used this data you would be cheating yourself out of some reserves.



Above is what the result looks like, virtually the same presentation as a standard P/z. Although the values for OGIP and drainage area are different, a thicker pencil would account for the difference.

The next plot shows the results of a mathematical model superimposed over the recorded data. This is the same type of model I use in my welltest analysis work. As in the previous examples I have chosen a fracture model because it fits the data best. It also makes geological sense.



In this presentation the red line and the black points represent the raw data. The model results are the solid yellow and blue lines. What is important here is the fit on the pressure data. As you can see it is very good. This production projection assumes that the wellface pressure stays constant at 900 psi for the life of the well.

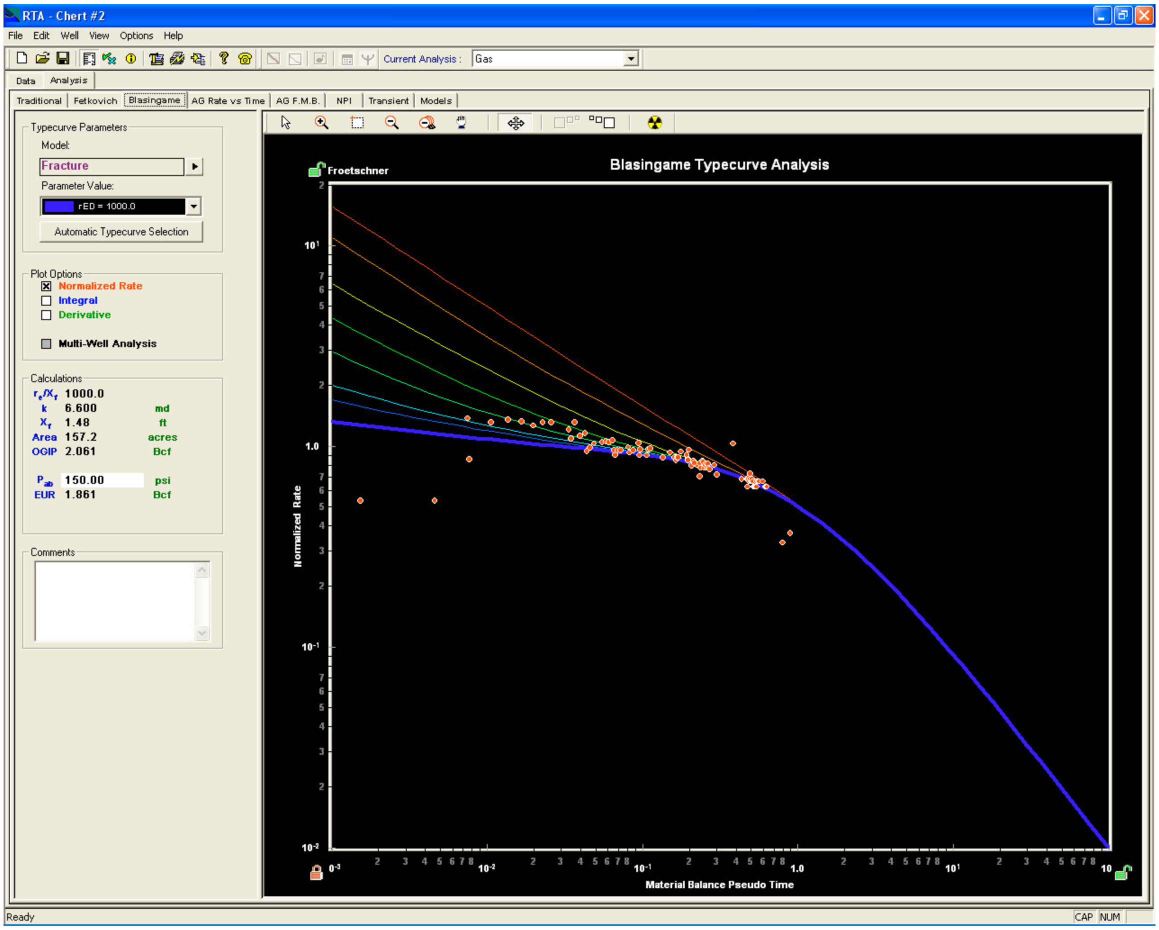
This is all very interesting but how does this help us decide to drill a well? In this case the existing well is draining only 70 acres. Some type of permeability barrier exists 1000' from the wellbore. If your seismic shows additional structure beyond this 1000' limit then you can be assured that the new well and this one will not be sharing the same reserves.

CHERT WELL #2

Let us now look at the second well in the field. This well was actually drilled and plugged many years ago before a gas market existed. The well was reentered and put on production. Although the AOF was not nearly as high as the previous well, the flow rate has stayed fairly constant since it was put on line.

This chart is a little busier than the last example because the well makes oil and water in addition to gas. The gas production is the red line and the wellface pressure is the black line. In this case the wellface pressure was calculated from flowing tubing pressure because the well has a packer. Casing pressure provides much better data and should be used when possible. Notice how little the flowrate has dropped, from about 1.7 MMcfd to 1.4 MMcfd over the period.

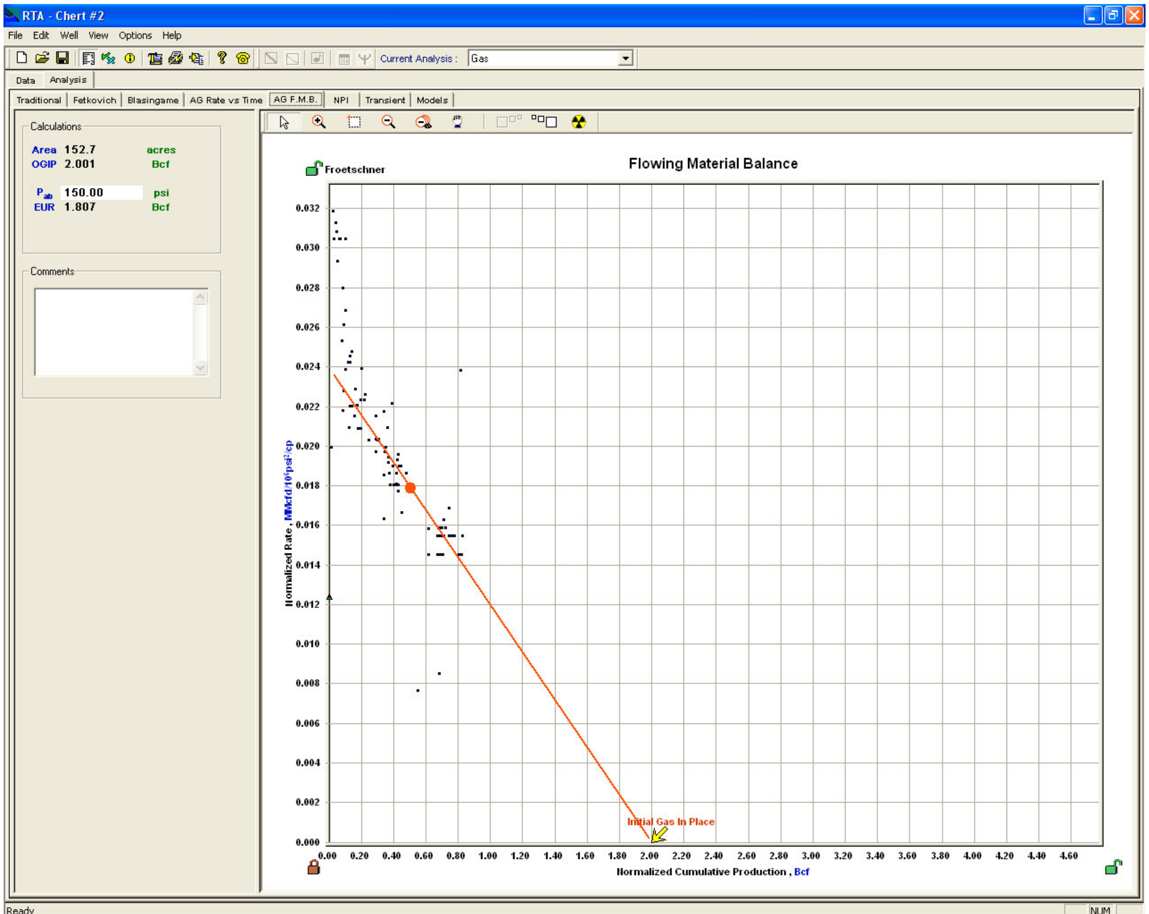
When Mr. Blasingame is introduced to the data the picture is a little different from the one in the previous example.

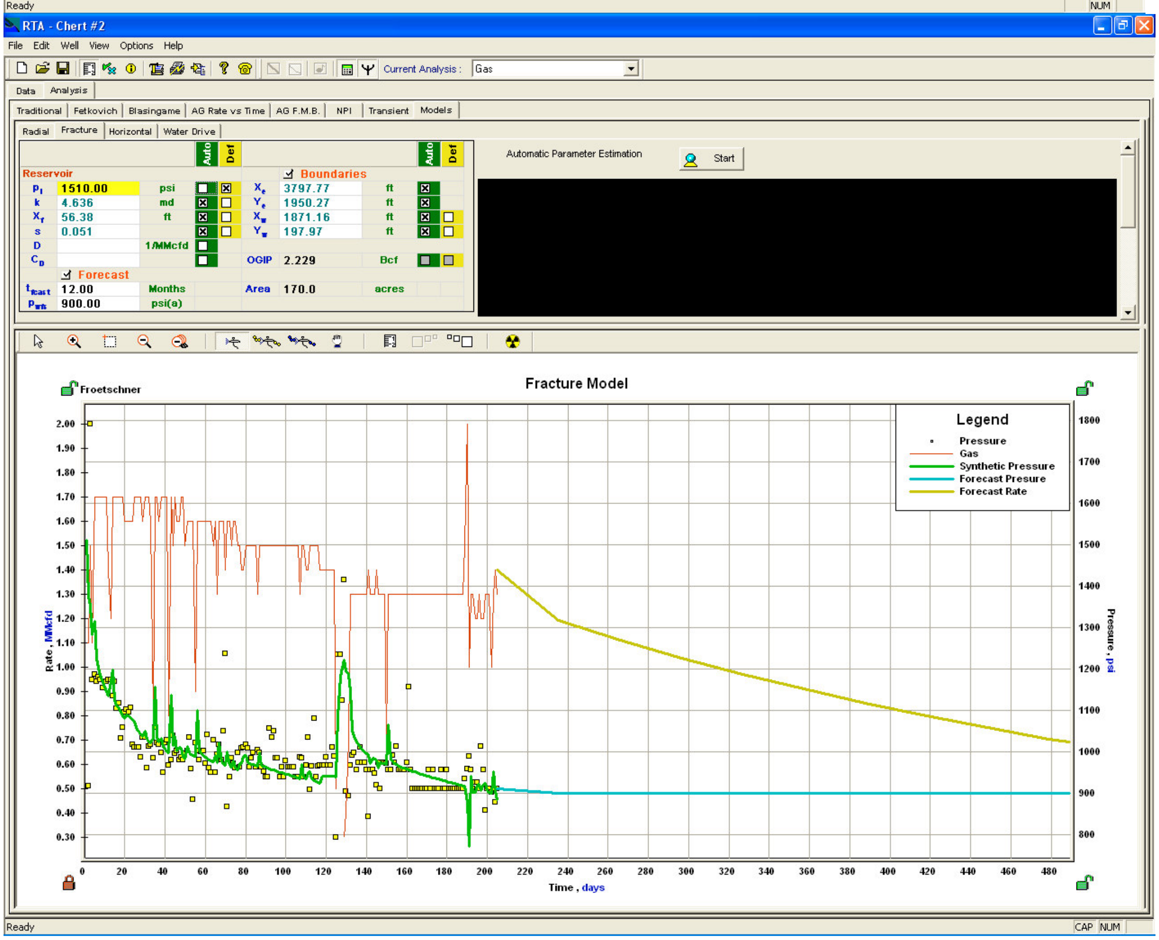


In this case all of the data points are on the "Transient" side of the curve. This indicates that the well has not seen the limits of the reservoir. A strong argument can be made that the well is just entering the depletion stem. Let's assume that this is the case. From the box on the left you can see that this well is draining about 160 acres and has over 2 BCF of gas in place.

Also notice that the frac half-length is shorter, at only 1.5 feet. This well could also be accurately modeled using the Radial technique. So why is this well producing so much better than the previous well? The perm is almost 10 times higher.

Just to be thorough I will show the Flowing Material Balance and Model for this well.


RTA - Chert #2
File Edit Well View Options Help
Current Analysis : Gas
Data Analysis
Traditional Fetkovich Blasingame AG Rate vs Time AG F.M.B. NPI Transient Models
Calculations
Area 152.7 acres
OGIP 2.001 Bcf
150.00 psi
EUR 1.807 Bcf
Comments
Froetschner
Flowing Material Balance
Normalized Rate , MMcfd/10⁶psi²/cp
Initial Gas In Place
Normalized Cumulative Production , Bcf
Ready
NUM


RTA - Chert #2
File Edit Well View Options Help
Current Analysis : Gas
Data Analysis
Traditional Fetkovich Blasingame AG Rate vs Time AG F.M.B. NPI Transient Models
Radial Fracture Horizontal Water Drive
Auto Def
Reservoir
1510.00 psi
k 4.636 md
56.38 ft
s 0.051
D 1/MMcfd
Forecast
12.00 Months
900.00 psi(a)
Boundaries
3797.77 ft
1950.27 ft
1871.16 ft
197.97 ft
OGIP 2.229 Bcf
Area 170.0 acres
Automatic Parameter Estimation
Start
Froetschner
Fracture Model
Legend
Pressure
Gas
Synthetic Pressure
Forecast Presure
Forecast Rate
Rate , MMcfd
Pressure , psi
Time , days
Ready
CAP NUM

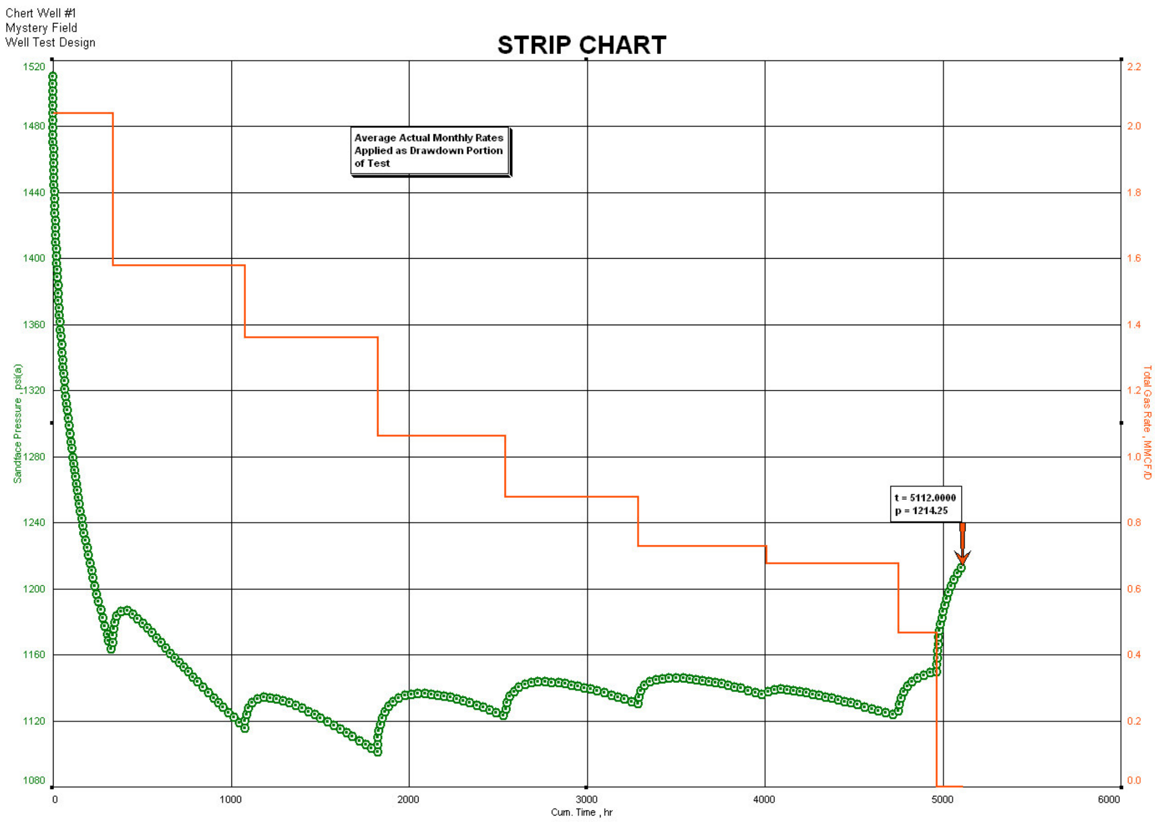
The model, Flowing Material Balance and Blasingame analysis all fit the data very well and indicate that this well is draining about 160 acres.

If you are considering offsetting this well, you better check your seismic and look for a location that is over 160 acres away. Any closer and you will be sharing reserves.

WHY NOT SHUT THE WELL IN FOR A BUILDUP

As I mentioned above, one of the partners wanted to run a six day buildup and use that data for a P/z analysis. In an attempt to show them that this was a futile exercise I constructed a mathematical model using my new found knowledge of the reservoir.

The plot below depicts the monthly averaged production from the well and what the model says the flowing pressures should be.



This shows that after 6 days of shutin the well is still building rapidly. With this little amount of buildup I would not even attempt to extrapolate to P*. I would buy all of the reserves I could based on this type of analysis.

I hope this analysis provides some insight into the type of information that can be obtained from good data. If you have a field where you think this may be applicable please give me a call. Or if you think I am full of bull let me know that also.

Sincerely,

William M. Johnson
Managing Partner