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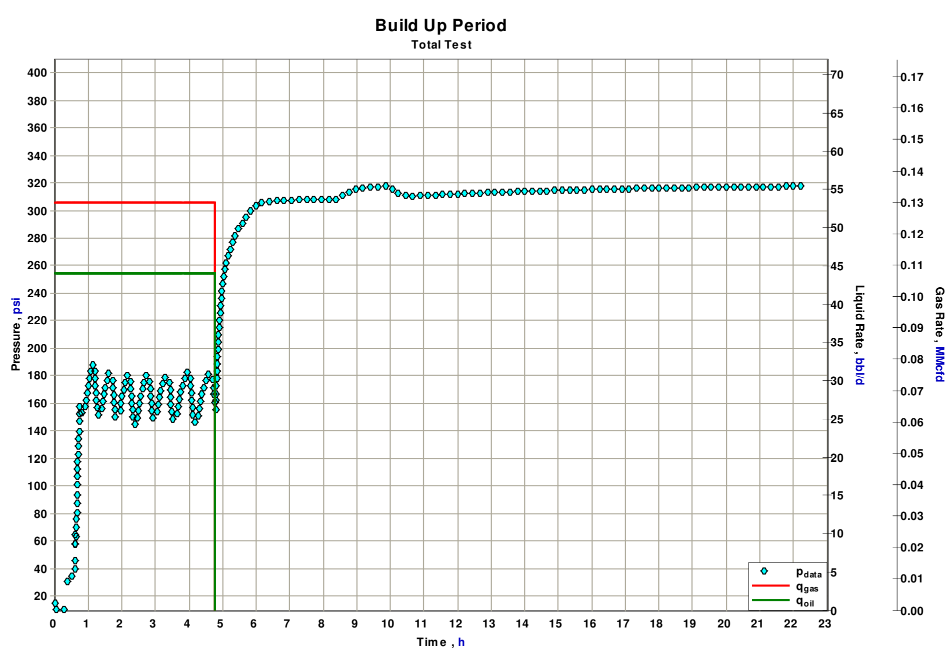
December 14, 2005

J. R. Ewing.
Big Oil Co..
South Fork Ranch
Dallas, TX. . 75230

I was called in after the fact on this test.. It is a tight hole so I don't even know what part of the country it is in. The formation is unknown. Porosity, water saturation and net pay were supplied by the operator. Unfortunately these were guesses because the zone was not logged due to lack of rat hole. We did not discuss the test design before it was conducted.

This test is interesting for several reasons. The operator decided that they wanted an open hole completion and set pipe above the zone. After drilling out the plug the operator found cement all the way to TD. They drilled out the cement leaving what they thought was a 3 7/8" hole inside a 61/4" cement "sheath" This would apparently yield a very poor completion efficiency.

The well was swabbed in and flowed. Below is an unfiltered view of the data as recorded.



As you can see there is quite a bit of slugging during the flow period of the test. The rate used for the analysis was the total recovered oil prorated to the test time. Gas rates were handled similarly. Because of the complex flow dynamics of a Flowing Oil Well bad (non-reservoir) data is often recorded. One of the operators big concerns was the “hump” in the build up portion of the test. This is addressed in the report.

Another interesting aspect of this test is the very high GOR considering the bottom hole pressure. I address this in the evaluation.

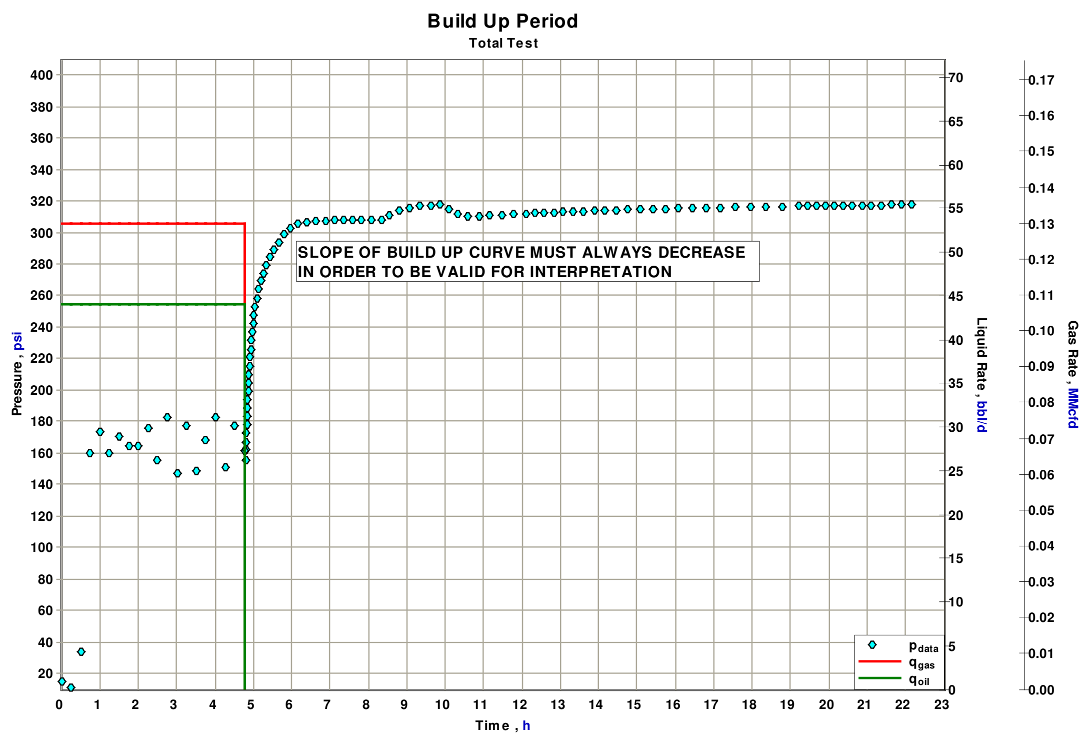
I hope that this is helpful. If you have an questions, comment or think I don’t know what I am talking about let me know.

Bill

Dear J.R.:

As you requested I have reviewed the data recorded during the well test on the Gusher #1. Although there was quite a bit of non-reservoir data I believe that the data is interpretable and provides insight into the production characteristics of the reservoir.

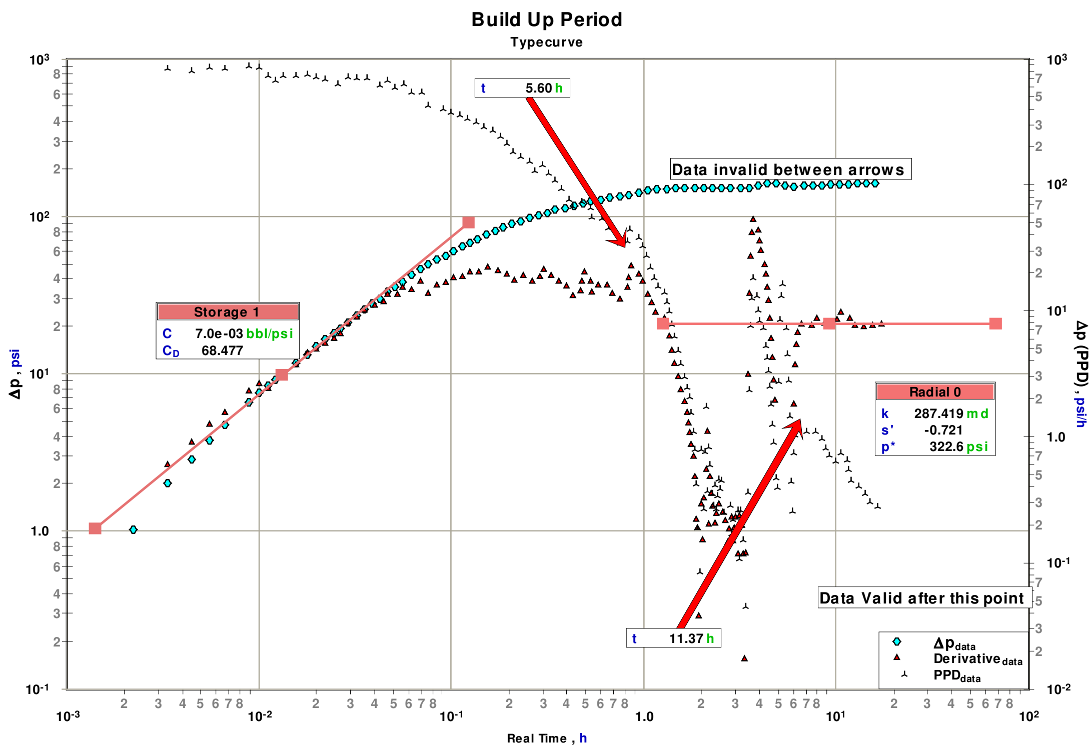
STRIP CHART



Above is a plot of the data set after editing and filtering. I removed data from the end of the test because the pressures were showing a slight decrease. From a reservoir point of view the pressure can never decrease. In the same way the derivative (or slope) of the pressure curve can never increase. If you were to use a pencil as a straight edge and follow the pressure build up, it should always flatten out. This is regardless of multiple zones, composite reservoirs etc. If, as in the case here, the slope increases then the data must be ignored for the interpretation. The next plot will deal with this more completely.

The other issue on this plot is oil and gas rates. As we discussed on the phone, there was quite a bit of slugging going on during the test. Through a technique called Superposition we can handle multiple rates, I do not believe however, that it is a valid technique in this case. For the rates in this test I simply took the total recovery of 7.4 bbls/3 hours for a daily rate of 60 bopd I used a gas rate of 130 mcfd. This combination yields a GOR of about 2200. This is well within the range of an oil well but the reservoir must be below bubble point. With a reservoir pressure of about 322 psia ,for the reservoir to be undersaturated the GOR would be about 60. It is therefore likely that a gas cap exists.

DERIVATIVE



Above is the Derivative presentation of the data set. Notice that there are three curves presented. The first curve I look at is the PPD curve. This is a qualitative curve that shows where the “reservoir” ends and the “non-reservoir data” begins. In order for the data to represent the reservoir, each point on the PPD curve must be lower than the one that precedes it. I have annotated the points on the PPD curve where the data is non-reservoir and must be ignored in the interpretation.

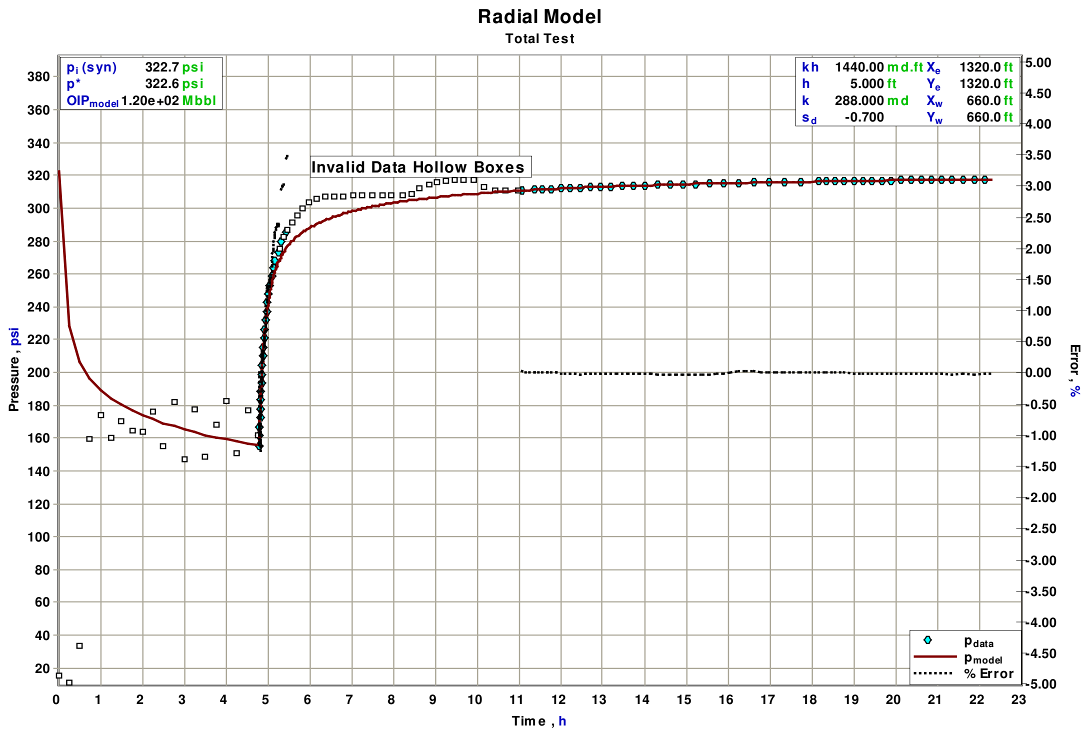
It is not at all uncommon for a flowing oil well to show this type of behavior. Phase segregation is often the cause. Liquids will enter the wellbore then get pushed out by a gas bubble. As the bubble travels upwards it expands until it hits the top of the wellbore and stops. At this point the pressure at the bottom of the wellbore will increase, sometimes dramatically, until the fluid is forced back into the formation. You mention in your write up that no fluid level was detected on the way out of the hole, this is what I would expect after seeing this data.

Notice that at the end of the data set, after the second arrow that the PPD is again in a smooth downward trend. This is valid reservoir data. I have superimposed a Radial Flow Solution to this portion of the curve. The permeability calculates to be about 287 md. with a skin of –0.7 and P* of 322 psia.

The skin of –0.7 indicates that the test "sees" a bigger wellbore than what is used in the calculation. It appears that you rconcerns of having a very small borehole are unfounded. Although you have cement in the openhole, it is not adversely affecting the production.

Based on these findings I will attempt to model the test using a Radial Model

RADIAL MODEL



Above is a plot of the data with the results of my model superimposed. On the right-hand axis is the % difference between the actual data and my model. As you can see the difference is virtually 0% over the valid portion of the test. I have shown the bulk of the invalid data as hollow boxes. Notice also that the model actually fits the flow portion of the test reasonably well also. The flow period rarely matches on a flowing oil well, for all the reasons mentioned earlier. In this case however a surprisingly good match was obtained.

The other thing you should notice is the $P_{I(syn)}$ in the box in the top left. This value is calculated by extrapolating the build up for 12 months then adding back in the production. In this case I believe that it is valid to use this value for the initial reservoir pressure P_i.

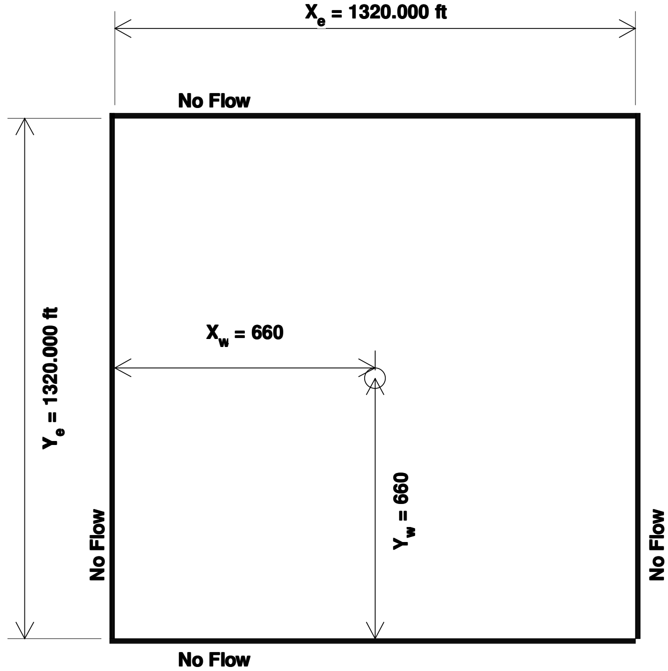
On the next page is a schematic of the model I constructed. Please understand that the outer boundaries are not based on this test. The duration was to short to allow for boundary determination as the test appears to have only "looked" out into the reservoir about 500'. I used 40 acres for convenience.

Radial Model

k = 288.0000 md
s_d = -0.700
OIP_{model} = 120.4 Mbbl

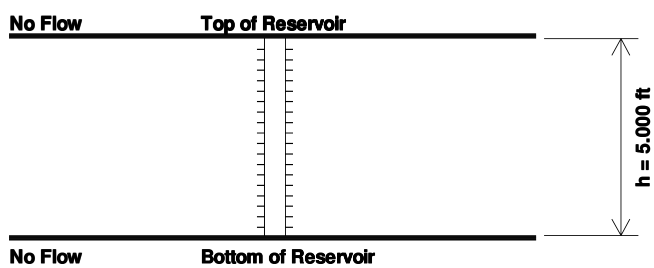
Plan View

(Not to scale)

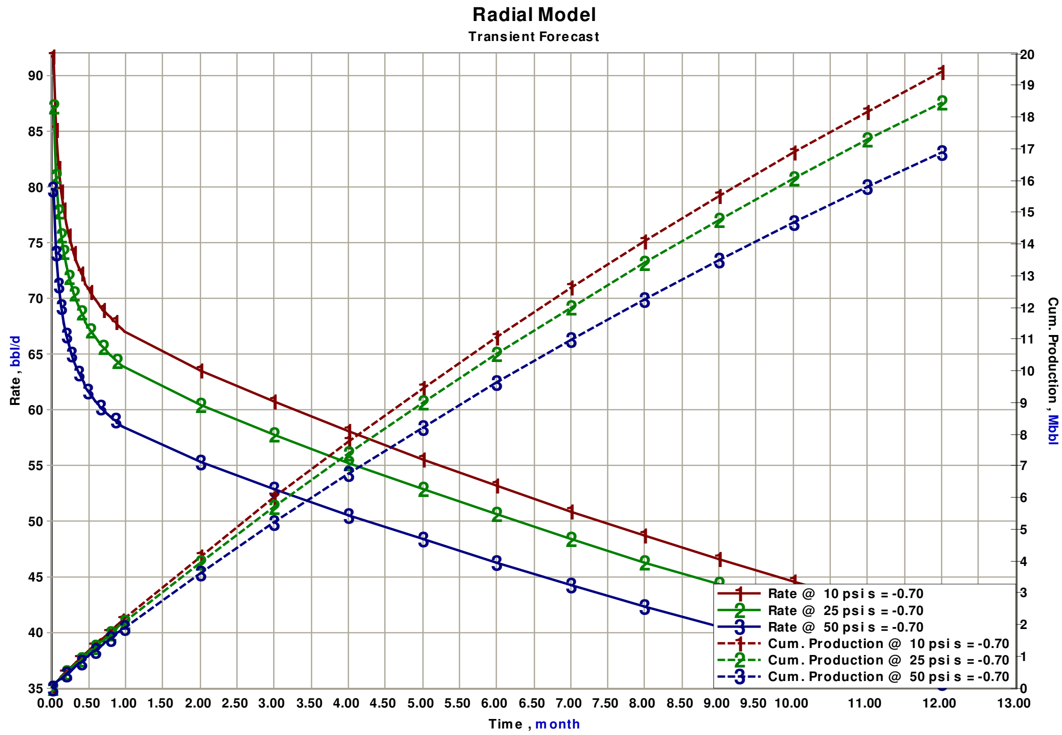


Side View

(Not to scale)



FORECAST



Above is a production forecast for this well. This model assumes constant compressibility, single phase flow and is therefore very limited. A more accurate model would require a simulation, which I can provide, but is probably overkill.

CONCLUSIONS

- This appears to be a saturated oil reservoir, probably with a gas cap
- Initial reservoir pressure is 322 psia
- Reservoir permeability within 500' of the wellbore is almost 300 md.
- The completion appears to be without skin damage
- Using the supplied parameters, the OOIP on 40 acres is about 1 MMbo
- Although no evidence of Pressure Support was evident during the test, it may exist.

RECOMMENDATIONS

Obviously a completion has already been made on this well, and I concur that it should be a good well. With the limited information available it is impossible to accurately estimate reserves. I typically warn about getting greedy and producing the well too hard in this section. In the case of this well the permeability is so high and the reservoir pressure so low that coning water would be difficult.

I mentioned in the **CONCLUSIONS** section that no pressure support was seen on the test. With the perm of the reservoir a water drive would be nice. If there is no natural pressure support you should consider an injection well. I do not believe that you need to be in a hurry with the pressure support because the reservoir is already below bubble point. I doubt that you will ever get the pressure high enough to force the gas back into solution. It is likely however that you will drive oil into the gas cap.

I might also advise you to keep track of oil, gas and casing pressure daily, on this well. This would be a good candidate for “Rate Transient Analysis”. This technique is a flowing material balance and useful for determining reserves and drainage area. I address this in an article on my website. It is very definitive on reserves in place and determining if natural pressure support exists.

Thank you for giving me the opportunity to evaluate this test for you. Let me know if I can answer any questions on this test or if you have any on the RTA analysis technique. Please feel free to share this pdf file with your partners and print as many copies as you want.

I will send a bound copy in the mail.

Thanks again and hope this helps.

Sincerely,

William M. Johnson P.E.
Managing Partner