RESERVOIR ENGINEERING FOR GEOLOGISTS
Part 6 – Well Test Interpretation

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Let's start off with a simple situation:
- Well A produces at 100 bopd from a reservoir that contains 1 millions barrels of oil.
- Well B also produces at 100 bopd from a reservoir that also contains 1 millions barrels of oil.

Are these two wells worth the same?

The answer is NO. This is because Well A is in a high permeability reservoir, but has a zone of reduced permeability around the wellbore (damage caused by drilling mud filtrate invasion or clay swelling). If this well were to be stimulated its rate would increase significantly. On the other hand, Well B is in a low permeability reservoir, which is the factor that limits its production rate.

How can we identify the differences between these two wells? The answer is well testing.

Well testing, often called pressure transient analysis (PTA), is a powerful tool for reservoir characterization. The following information can be extracted from well tests:

- Permeability – The value obtained from a well test is much more useful than that from core analysis, because it represents the in-situ, effective permeability averaged over a large distance (tens or hundreds of metres).

- Skin (damage or stimulation) – Most wells are either damaged or stimulated, and this has a direct effect on the deliverability of the well. The skin is a measure of the completion effectiveness of a well. A positive skin (typically +1 to +20) represents damage, while a negative skin (typically -1 to -6) represents improvement.

- Average reservoir pressure – This parameter, which is either measured directly or extrapolated from well test data, is used in material balance calculations for determining hydrocarbons-in-place.

- Deliverability potential – The IPR (inflow performance relationship) or the AOF (absolute open flow) is used in forecasting a well's production.

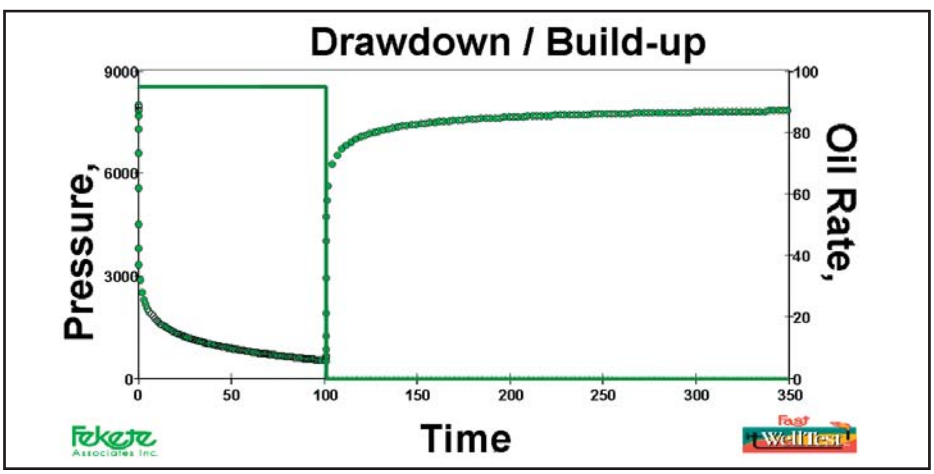

Figure 1. Drawdown and Build-up Test.

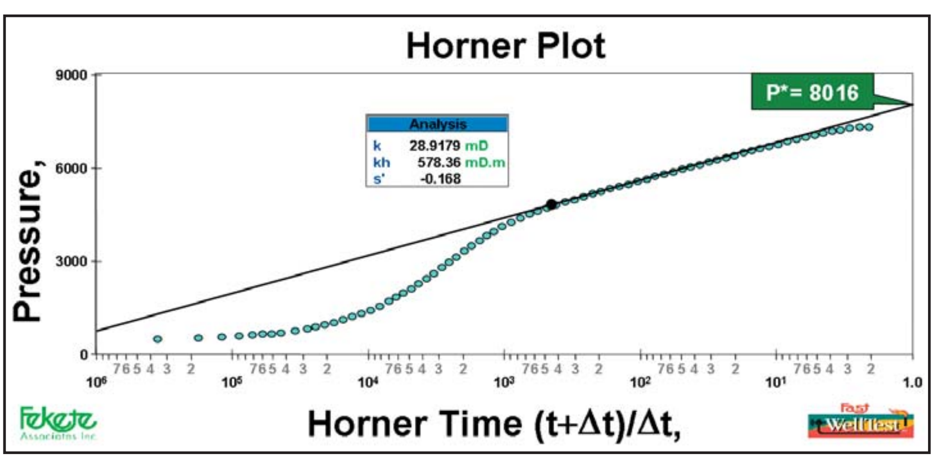

Figure 2. Semi-log (Horner) Plot of Build-up Data.

- Reservoir description – Reservoir shape, continuity, and heterogeneity can be determined from pressure transient tests

- Fluid samples – The reservoir fluid composition and its PVT (pressure-volume-temperature) properties can have a significant effect on the economics and production operations.

Well testing is also an integral part of good reservoir management and fulfills government regulations.

FUNDAMENTALS:
- A well test is a measurement of flow rate, pressure, and time, under controlled conditions. While the well is flowing, the quality of the data is often poor, thus the data during a shut-in is usually analyzed.

- Opening or closing a well creates a pressure pulse. This "transient" expands with time, and the radius investigated during a test increases as the square-root of time. The longer the flow test, the further into the reservoir we investigate.

- Because of the diffusive nature of pressure transients, any values determined from a well test represent area averages and not localized point values.

- The analysis of oil well tests is similar to that of gas well tests. The theory is derived in terms of liquid flow, and is adapted for use with gas by converting pressure to "pseudo-pressure (ψ)" and time to "pseudo-time(t_a)."

- The practice of testing a flowing oil well and a gas well is similar – measure the bottom-hole pressure. However, for a pumping oil well, it is often not easy to measure the bottom-hole pressure directly, so it is usually calculated from surface data and Acoustic Well Sounders, thereby having a greater potential for error.

This article will concentrate on the analysis of the two most common well test types in Alberta, namely "build-up" and "deliverability" tests.

- Build-up test*:
  To conduct a build-up test, simply shut the well in. It is obvious that a build-up test must be preceded by one or more flow periods. Figure 1 shows the simplest possible build-up, a shut-in that follows a single constant rate. In practice, the period preceding the buildup will often consist of variable rates, and even multiple flows and shut-ins. These non-constant flow periods cannot be ignored, but must be accounted

**Injection and fall-off tests are analyzed the same way as a build-up – simply replace the production rate by the injection rate, and the pressure rise by the pressure fall.*

for during the analysis. This is done through a mathematical process called superposition, which converts these variable flow periods into an equivalent constant rate.

• Deliverability tests:
The purpose of these tests is to determine the long term deliverability of a well, rather than defining the permeability and skin (as in build-up tests). There is one overriding factor in these tests; it is that at least one of the flow durations must be long enough to investigate the whole reservoir. This condition is known as "stabilized" flow. Sometimes it is impractical to flow a well for that long. In that case, the stabilized condition is calculated from the reservoir characteristics obtained in a build-up test.

INTERPRETATION:
Interpretation of well test data is often conducted in two stages. The first is a diagnostic analysis of the data to reveal the reservoir model and the second is modeling of the test.

DATA PREPARATION:
To analyze the build-up data, it is transformed into various coordinate systems in order to accentuate different characteristics. The most useful transformation is the "derivative" plot, obtained as follows:

1. Plot the shut-in pressure, p (for gas*, ψ) versus log $\{(t+\Delta t)/\ \Delta t\}$, where t is the duration of the flow period (or the corresponding superposition time, when the flow period has not been constant) and Δt is the shut-in time. A semi-log plot of this is called a Horner plot and is shown in Figure 2.
2. Determine the slope of the Horner plot at each Δt. This slope is called the derivative.
3. Plot the derivative versus Δt on log-log graph paper (Figure 3).
4. Calculate Δp (for gas*, $\Delta\psi$), the difference between the build-up and the last flowing pressure.
5. On the same log-log graph as the derivative, plot Δp (for gas, $\Delta\psi$) versus Δt (Figure 3).

DIAGNOSTIC ANALYSIS:
The buildup is divided into three time regions – early, middle, and late time. The middle time represents radial flow, and it is not until middle time is reached that the permeability can be determined. In Figure 2, the permeability is calculated from the slope of the semi-log straight line, and in Figure 3, from the vertical location of the flat portion of the derivative. These two answers should be the same.

The skin is calculated from the Δp curve. In Figure 3, the larger the separation between the curves in the middle time region, the more positive is the skin.

Early time represents the wellbore and the near-wellbore properties (effects of damage, acidizing,

**In well testing the corrections caused by pseudo-time are usually negligible. For simplicity this article will use "t" rather than "ta".*

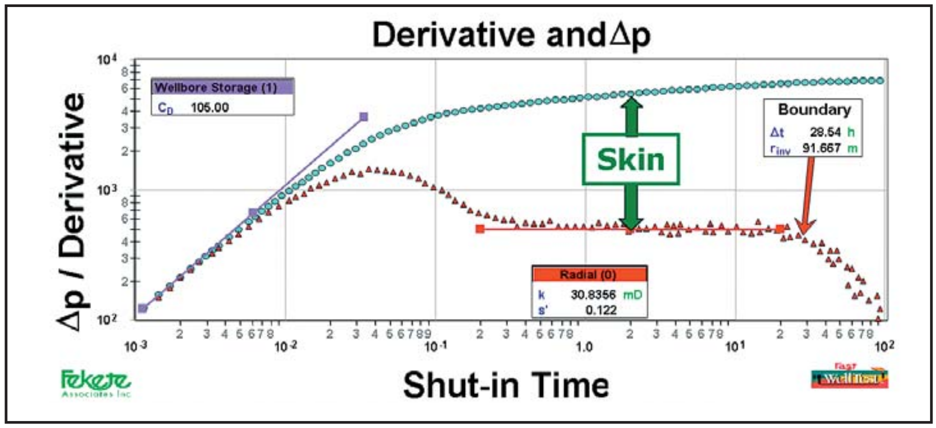

Figure 3. Derivative Plot of Build-up Data.

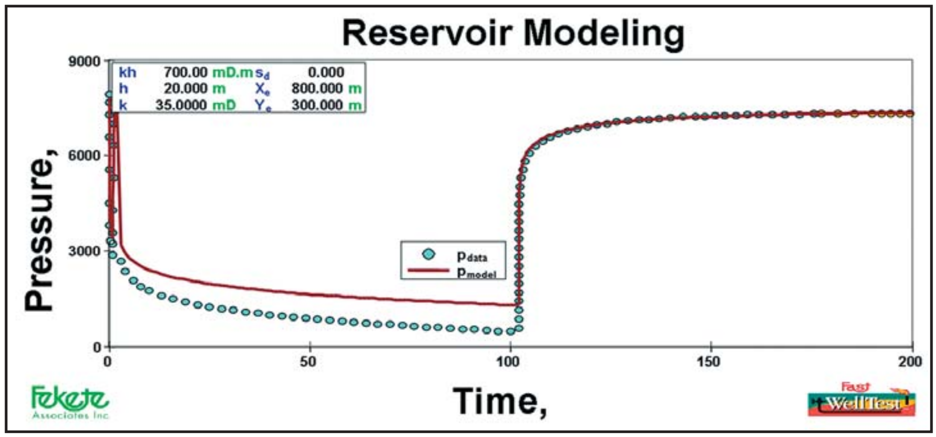

Figure 4. Modeling: Comparison of Synthetic and Measured Pressures.

or hydraulic fracture). It is often associated with a (log-log) straight line of fixed slope. A slope equal to "one" means "wellbore storage," and during that period, nothing can be learned about the reservoir because the wellbore is still filling up. A slope of "half" typically means linear flow as a result of a hydraulic fracture. From this straight line, the fracture length or fracture effectiveness can be calculated if the permeability is known.

The period after middle time is known as late time, and it reflects the effect of the reservoir boundaries and heterogeneities. It is from this region that the reservoir shape can be determined. A straight line of slope approximately "half" would indicate a long, narrow reservoir. A straight line slope approximately "one" could imply a low permeability reservoir surrounding the region investigated during middle time. If the derivative trends downward during the late time period, it could indicate an improvement in permeability (actually mobility) away from the well. If this downward curvature is severe, it might be indicative of a depleting reservoir.

The average reservoir pressure (p_R) is obtained by extrapolating the semi-log straight line to infinite shut-in time (=1 on the Horner plot). This extrapolation is called p* and it is used, along with an assumed reservoir shape and size, to calculate the average reservoir pressure. For short flow durations, for example in a DST or in the initial test of a well, the correction from p* to p_R is negligible, and p* does equal p_R.

MODELING:
Once the analysis has been completed and an approximate reservoir description deduced, a mathematical model of the reservoir is constructed. This model utilizes the production history of the test (all the flow and shut-in data) to generate "synthetic" pressures which are then compared with the pressures that were actually measured during the test (Figure 4). The values of the parameters in the model (permeability, skin, distances to boundaries, etc.) are varied until an acceptable match is obtained between the synthetic and measured pressures.

This process, called modeling or history matching, is a powerful mathematical tool, but must be used with caution, as it can result in mathematically correct, but physically meaningless answers. Some very complex reservoirs (multi-layers, heterogeneous, etc.) can be modeled using sophisticated mathematical models, but for these interpretations to be meaningful, they must be consistent with known geological descriptions and realistic physical well completions.

TYPES OF WELL TESTS:
• RFT*, WFT*, MDT*, RCI*, FRT* – These are tests of very short duration (minutes) conducted on a wireline, usually while the well is drilling. The popular use is for determining the reservoir pressure at various depths.

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**Trade Marks: RFT=Repeat Formation Tester, WFT=Wireline Formation Tester, MDT=Modular Dynamic Tester, RCI= Reservoir Characterization Instrument, FRT=Flow Rate Tester*

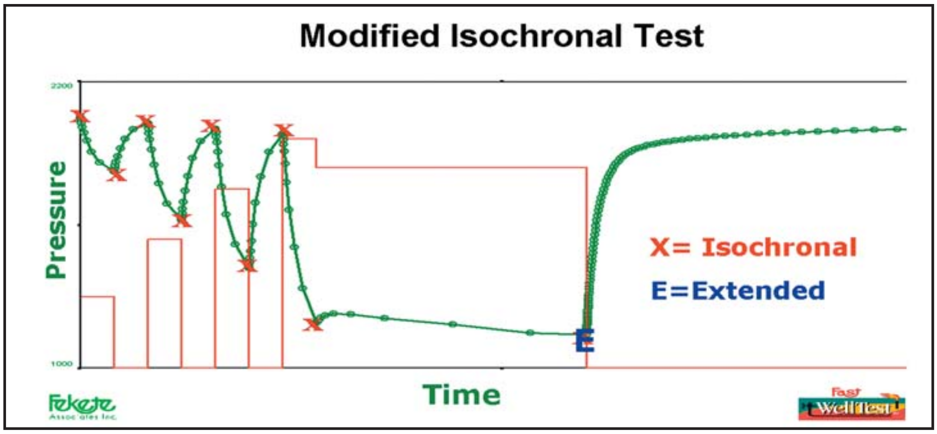

Figure 5. Modified Isochronal Test.

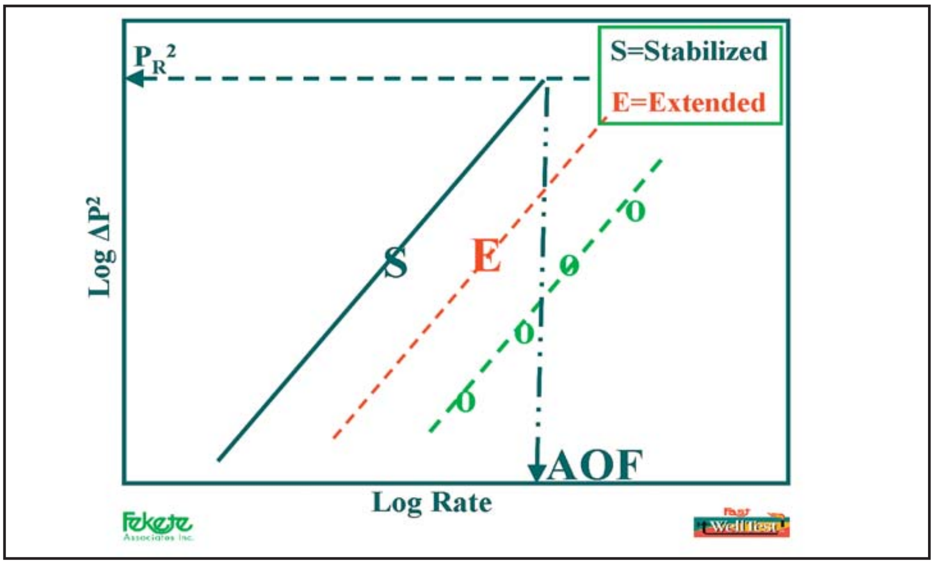

Figure 6. AOF Plot.

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- DST (drill stem test) – conducted during drilling of exploratory wells, to determine reservoir fluids, reservoir pressure and permeability. Onshore DSTs are usually open hole, whereas offshore DSTs are cased hole. An open-hole DST typically consists of a 5-minute pre-flow and a 30-minute build-up, followed by a 30-minute flow and a 1-hour build-up. It is analyzed exactly like the build-up test described above. Because of the short flow durations, p* does equal p_R. It should be noted that on most “scout tickets” what is reported is not p* or p_R, but the ISI (initial shut-in pressure) and the FSI (final shut-in pressure). In low permeability reservoirs, the FSI is usually less than the ISI, and sometimes this difference is misconstrued as being caused by depletion occurring during the test (which implies a small reservoir and could lead to abandonment of that zone)

- Build-up – The well is shut-in, following one or more flow periods. The pressure is measured and analyzed to give permeability, skin, average reservoir pressure, and reservoir description. This is the most commonly analyzed test because it is often quite long (several days of flow and several days of shut-in) and the data quality is usually good.

- Interference or pulse – These tests involve flowing one well (active) but measuring the pressure at another well (observation), and are used to determine interwell connectivity.

- IPR – These tests are designed to yield the long-term deliverability of the well, and are not concerned with determining the reservoir characteristics. The deliverability test for an oil well is called IPR (inflow performance relationship). It describes the inflow into the wellbore at various bottom-hole pressures. The test consists of a single flow until stabilization is reached, at which time the oil and water flow rates and the flowing pressure are measured. An IPR is plotted according to known relationships such as the Vogel IPR equation.

- AOF (absolute open flow) - An AOF test is the gas well equivalent to a liquid IPR test. It too must have at least one flow rate to stabilization. It differs from a liquid IPR in several ways:
  - Often more than one flow rate is required. This is because gas flow in the reservoir can be turbulent (liquid flow is laminar) and the degree of turbulence can be assessed only by utilizing multiple flow rates.
  - The governing equation is not Vogel’s but a “Back-Pressure Equation” of the form $q=C(\Delta p^2)^n$, where q is the flow rate, C a constant that depends on the well’s characteristics (permeability, skin, etc.) and n is a measure of turbulence. Values of n range from 1 to 0.5, where n=1 means laminar flow and n=0.5 means fully turbulent flow.
  - P^2 is used instead of pseudo-pressure as a simplification.
  - Typically four different flow rates are selected (say 4 hours each) with a 4-hour intervening shut-in. These are called the isochronal points. If the time to stabilization is too long, then the “stabilized” rate is replaced by an “extended” flow (3 to 5 days), followed by a 1 to 2 week build-up (Figure 5). The results of the build-up analysis are used to calculate what the stabilized flow rate and pressure would have been.

  A best-fit straight line is drawn through the isochronal data on a log-log plot of Δp^2 versus q. A line parallel to that is drawn through the stabilized point (NOT the extended point) (Figure 6). This is the stabilized deliverability line and is used for determining the flow rate that corresponds to any specified back-pressure. Extrapolating this line to p_R^2 gives the maximum deliverability potential of the well (when the back-pressure is zero, $\Delta p^2 = p_R^2$). This maximum is called the AOF (absolute open flow) and is one of the most commonly used indicators of the well’s deliverability potential.

- PITA (perforation inflow test analysis) – In these tests, sometimes referred to as PID (perforation inflow diagnostic), the well is perforated and the pressure rise in the closed wellbore is recorded, and interpreted to yield an estimate of permeability and reservoir pressure. These tests are useful for “tight gas” where most other tests would take too long because of the very low permeability.

REFERENCES

Energy Resources Conservation Board. 1979. Gas Well Testing – Theory and Practice. ERCB, Guide G3 (Directive 034), 547 p.

Lee, J., Rollins, J.B., and Spivey, J.P. 2003. Pressure Transient Testing. Society of Petroleum Engineers, Textbook, Vol. 9, 376 p.

Look for our next article on “Rate Transient Analysis” in the May issue of the Reservoir.

This article was contributed by Fekete Associates, Inc. For more information contact Lisa Dean at Fekete Associates, Inc.