Candidate Selection for Surface Testing

Halliburton developed the SPIDR® well testing system into the preeminent method of testing gas and gas condensate wells from the surface. Through this experience we’ve found one of the critical steps in the process of designing a surface test is selection of candidate wells. Conducting a surface well test on a well that is a poor candidate can result in erroneous reservoir characterization. With this in mind, determining that the well is in critical flow has proven to be the most important aspect of screening wells for surface testing. This article will discuss wells that are poor candidates because they are not in critical flow and also the pressure responses that may be observed in these types of wells.

Wells that flow below the critical rate are poor candidates for surface testing. In order to accurately model surface pressures to bottomhole pressures, one of the constraints is that the well must have constant mass flow and constant component flow while on production. Wells that do not continuously unload their produced liquids satisfy neither of these criteria. The consequence of this is that flowing bottomhole pressures (BHP) calculated from surface data will be in error because they do not account for the hydrostatic head of the liquid accumulating in the wellbore while the well is on production. This will also have an effect on the analysis for skin. Since the calculated flowing BHPs are too low, the Delta P between flowing and shut-in will be too high, resulting in an artificially large skin.

The annotated plot included with this article illustrates the problems presented by wells that do not continuously unload their produced liquids. The plot (Figure 1) overlays the SPIDR® gauge wellhead pressures (WHP) and the pressures measured by a downhole gauge (DHG).

![Figure 1: SPIDR® gauge and DHG Pressures](image)

There are a couple of important points to take away from this plot. First of all, the flowing WHP’s from the SPIDR® gauge are not at all representative of the downhole response; the surface pressure decline is much more rapid. The reason for this decline is that the well is NOT flowing above the critical unloading velocity. Prior to shut-in, this well was flowing ~450 MCF/D up 3½” tubing at about 570 psia. A quick
check of the unloading charts available on our website indicates that the critical rate is about 1,900 MCF/D. The well is clearly below the critical unloading rate. Liquid is accumulating in the wellbore, increasing the hydrostatic head and causing the decline of the surface pressure data.

The second point of interest from the overlay plots is observation of liquid reinjection. When the well shuts in, the liquids in the wellbore fall back and form a column covering the perforations and the downhole gauge. As the shut-in progresses, gas influx from the reservoir will displace the liquids in the wellbore and force them back into the formation, eventually uncovering the perforations. During the build-up on this well, this reinjection lasted for about the first three hours of the shut-in. While reinjection is taking place, there is a gas/liquid interface in the wellbore between the surface gauge and the perforations. The presence of this interface masks reservoir response, and makes analysis for skin, permeability and P* impossible until the liquid reinjects into the formation below the top of the perforations. It is important to note that the downhole gauge located in the tubing above the perforations also sees liquid reinjection effects during this test. Initially, the DHG sees a normal build-up response, but then the pressure suddenly drops and eventually returns to the expected build-up response. The reason for this is that at first the top of the liquid column is above the DHG. A short time later, the liquid column drops below the gauge, causing the DHG to see the same gas/liquid interface that the SPI® gauge did at the surface and masking reservoir response from the downhole gauge as well. Eventually, the liquids reinject below the top of the perforations and both the DHG and SPI® gauge can see reservoir response again. Figure 2 displays this process.

These observations illustrate the importance of selecting good candidates when testing from the surface. It is important to understand that not all wells can be tested from the surface and that the analysis derived from poor candidates will likely be erroneous. Halliburton offers free consultation and pressure transient test planning. We are available 24 hours a day to assist with any well testing needs that may arise.

© 2012 Halliburton. All Rights Reserved