The SPIDR surface well testing system

A METHOD WAS developed over 20 years ago that would provide an alternative to the conventional method of capturing pressure at mid-perforation depth for purposes of Pressure Transient Analyses in both Pressure Build-ups (PBU) and flowing or Drawdown (DD) tests in gas and gas condensate wells.

In this method pressure is captured at the wellhead with a high-frequency, high-resolution pressure gauge that is packaged, installed and calibrated to minimise ambient temperature effects at surface. After collection, that pressure data is accurately converted to BHP and conventional pressure transient analysis is performed in order to derive common reservoir parameters such as skin, permeability and P^*.

In many areas of the world production horizons are being explored for at ever more increasing depths. With increased depths come increased pressure and temperatures along with the likelihood of sour gases (CO^2 or H^2S) being produced in the flow stream. By testing at the wellhead you are eliminating the risk of either losing equipment in the wellbore, causing a potential costly fishing job or even risk losing the well altogether. Also, running wireline inside tubulars can expedite corrosion problems or damage plastic coatings, etc.

In addition, downhole restrictions may not permit the running of equipment down the bore. It is also understood that as these depths and pressures increase the cost to run equipment goes up dramatically, especially in an offshore or remote environment.

In order to accurately convert surface acquired data to BHP, input information about the gas stream (gravity and composition) along with any liquids being produced (quantity and quality) and a wellbore schematic are needed. A proprietary modified Cullendar & Smith equation is used to perform the conversion of surface pressure to BHP. This algorithm has been empirically developed by performing hundreds of simultaneous comparisons with DH gauges on different types of wells in areas around the world. It is one of the most rigorous models available on the market today. Also the importance of having well testing engineers who are trained in analysing surface obtained pressure data cannot be underestimated.

A key issue in accurately converting surface pressures is to minimise temperature effects during the acquisition of the pressure data while having a method or algorithm to account for the phenomena of 'thermal decay'.

Thermal decay is commonly seen during build-ups where large amounts of heat are transferred to the wellhead during production but gradually decrease during the PBU causing the pressure at the surface to fall instead of build up. This is a common phenomena and it is only handled with an algorithm that accounts for this temperature change taking place at the wellhead. However, it's critical that these two temperature-related issues are individually accounted for and minimised as it is impossible to decouple the effects when both exist.

Another important issue revolves around the issue of liquid re-injection. This is the phenomenon of liquids being produced that fall into the wellbore when the well is shut in for the buildup. As the gas displaces the liquids, and the liquids are re-injected back into the formation, the surface gauge reading is inaccurate because of the presence of two phases in the

wellbore (liquid near the perforations and gas near the surface). Once the liquid is re-injected and the top perforation is uncovered, communication is established with the wellbore once again and the pressure response is valid.

The time for re-injection to occur is dependent on permeability and amount of liquid to be re-injected. It is typically recommended to perform a drawdown test after a PBU when liquid re-injection is suspected. If a boundary is reached while the liquids are re-injecting, surface measurements will not detect it and thus will invalidate the slope and analysis. A subsequent drawdown test would be required in order to compare the analysis of the PBU with the drawdown.

If the analyses match or are similar we could say with confidence that a boundary was not reached. However, if the numbers are dissimilar we would have more confidence in the drawdown analysis.

The limitations for this method of testing are: 1) The well has to be unloading all produced liquids (critical flow); and 2) Flowing at the wellhead without slugging. If these two parameters are met it is highly likely that the well can be tested at the surface regardless of how much liquid (oil and/or water) is being produced. In order to determine if gas or gas wells are suitable for this technology one of the first things to be done is to determine if the well is unloading its liquids. A common Dukler unloading chart is the first screening tool used. By knowing the production tubing I.D., the Flowing Tubing Pressure (FTP) along with the gas production rate (MMSCFD) we can easily determine if the well is unloading all liquids or not.

In summary, this technology is accepted in the Gulf Coast and Gulf of Mexico area of the US and employed by operators large and small as a no-risk RISK and low-cost alternative to running wire and gauges downhole for the purpose of pressure transient analysis.

In addition to being portable, easily transported and installed by a single person, it has the capability to continuously record wellhead pressure in excess of one year without interruption. Data can be automatically transferred by fibre optic or local access to the Internet if required.