How to control inflow to restrict gas influx

Early gas breakthrough can impair oil production while bleeding off reservoir pressure. After study and simulation, Statoil found a solution.

A commonly experienced problem in mature oil fields is late-life gas breakthrough, either from coning down from the gas cap or from high-permeability strata. Besides impairing oil production, gas influx can have two undesirable consequences—it reduces the pressure drive of the reservoir gas cap, and it can present a handling issue to the production facility.

Limited gas-handling capacity at the Heidrun Field processing facility resulted in wells being shut in when the gas-oil ratio (GOR) reached a particular threshold, regardless of the source. But total shut in seemed to be a inefficient solution to a common problem. Company engineers sought a more effective solution through the development of a better understanding of exactly how gas was invading the completion.

Typically, Heidrun development wells are drilled to a kick-off depth, then deviated and landed in the target reservoir. Casing is set, and a lateral production section is drilled. To effectively manage potential sand production, the wells are completed using an openhole gravel pack supported with wire-wrapped screens. Production enters the completion across the entire length of the screened completion. Wells are equipped with permanent downhole pressure gauges near the heel to monitor pressure, and fluid production is assisted by gas lift valves staged in the vertical section. At surface, a multiphase flowmeter is used to measure and classify all phases in the production stream. A sand-detection device also is included in the surface measurements.

A candidate well was chosen to perform a root-cause analysis that could possibly lead to a solution. Production logs run in 2008 clearly showed high gas influx in the top screen sections. However, it was unclear precisely where oil was entering the completion. For this reason a simple gas shut-off scheme using some sort of straddle liner was ruled out. The most desirable solution appeared to be one that achieved gas shut off without compromising oil production.

Formation complexities cloud the issue

The Heidrun reservoir consists of three Jurassic age sandstones—the Fangst group, the TIlje Formation, and the Åre Formation. It is heavily faulted and compartmentalized by a complex fault network associated with several stratigraphic barriers. Although the Fangst formations are of relatively good quality, the Tilje and Åre formations are quite complex, which complicates the prediction of formation flow patterns and location of fluid contacts.

Currently, production is being augmented by downdip water injection along with updip gas injection to sustain the gas cap drive. Sand management has been an issue from the outset, and several solutions have been tried. The openhole gravel pack sand-screened completion in long horizontal laterals is currently giving the best results.

While undesirable gas influx is always problematic, it can sometimes be tolerated. However, the deciding issue at Heidrun was the limited gas-handling capacity of the......
production platform. For the particular well under study, the GOR limit was around 600 to 650. The candidate well had been completed in 2002, and throughout its life production had been cyclical, depending on a variable GOR. One solution had been to cut back on oil production to mitigate the GOR so the well could be continuously produced, but that was not a viable option.

**Measurements set the stage**

Production team members had plenty of good data to help them. Production logging of the candidate well took place in 2006 and again in 2008 so that time-lapse comparisons could be made. During both logging runs, the well was operated at two rates to see what effect the rate would have on the log data. The well also was logged during a shut-in period to detect possible cross flow and to obtain accurate static reservoir pressure in each producing zone.

Careful analysis of the log data left little doubt that the majority of the gas influx was coming from the upper screen sections closest to the heel. A solution was sought that would reduce or eliminate the gas influx without impairing oil production.

Production engineers thought that insertable inflow control devices (ICDs) could solve the problem. ICDs have three advantages over a straddle liner shut-off technique: they minimize gas entry rate, stimulate flow from the remaining producing intervals, and can prolong well production life. Further study was launched to decide on the optimum type for the Heidrun field.

Schlumberger ICD screens are equipped with calibrated ceramic flow nozzles, the number and size of which can be determined through simulations and that are field-configurable. This means the completion can be customized on site to match production parameters. Simulations showed that the pressure drop across the straddled zones could be controlled by the nozzles, thus delaying gas breakthrough depending on fluid mobility ratios, stabilizing GOR, and minimizing the risk of bypassing reserves. The nozzles operate under the Bernoulli principle, meaning they operate independently of fluid viscosity.

**A peep at the pack**

Fluid enters the insert screen along its exposed length, and sand is controlled by the precise aperture between the wire wrapped around the outer surface. The fluid makes its way along the annulus between the screen jacket and the inner base pipe to the upper housing, where it passes through the ceramic nozzles. Its potential energy (pressure) is transformed into kinetic energy (flow rate) and is absorbed by the flow in the main production tubing, resulting in a pressure drop between the annulus and the tubing. The ICDs are self-balancing and respond to differences in rock properties along the producing zone.

**Designing the customized solution**

The methodology follows four steps:

1. Establish the base case. Use log data to create a production profile and a synthetic permeability profile;
2. Select the insert screen size, number of screens, and nozzle configurations. Use saturation, desired inflow distribution, pressure profiles, and nozzle-based ICD specifications to establish a series of nozzle size options as well as insert screen IDs. Use the simulator to determine the number of insert screens needed as well as their diameter, length, and nozzle distribution, starting at the heel. The simulator also can help decide if packers are required between the insert screens. In the candidate well packers were deemed to offer little advantage;
3. Perform the technical design and installation. Final design should allow for retrievability. Metallurgy must be consistent with well fluids and anticipated life. Deployment is by tractor without having to kill the well; and
4. Measure the results and capture learnings.

Production results bear out the decisions made during the design and implementation phases. The entire operation on the initial well took approximately six days. Learnings from the first well are expected to reduce this time on subsequent installations.