Case study: Northern Louisiana, United States

Mudzyme system removed near wellbore polymer damage, resulted in a commercially viable injection rate

Ideally, reservoirs used for gas storage wells have low reservoir pressures with high permeability and porosity so they can easily store and recover the large volumes of gas they store. When these types of reservoirs are drilled and completed, there can be problems. They have to be able to support the fluid column while drilling, effectively carry the cuttings out of the wellbore, and meet additional challenges resulting from gravel-pack screens.

To avoid these problems in two gas storage wells (no. 2 and no. 8), limit fluid in the formation, and reduce the chances of additional challenges from loading the dry reservoir with fluids, an operator in the James Sand formation in northern Louisiana drilled in with a polymer system that resulted in damage to the near wellbore area.

A calcium carbonate lost circulation material (LCM) was incorporated in the system to temporarily plug the formation pores while drilling. Similar fluid systems were used during the under-reaming and completion process to ensure minimal fluid loss and maintain circulation. A hydrochloric acid blend was used to clean up the fluid systems and dissolve the LCM.

In well no. 8, the Baker Hughes **OxiClean™ system** was squeezed across the gravel-pack screens and left to soak for two hours. The HCl blend was then squeezed to react with the LCM and formation, and was also allowed to soak for two hours. A falloff test was performed before establishing injection with gas to assess the treatment. The test results indicted additional treatment would be needed.

Before treating additional wells, Baker Hughes tested the fluids to identify the problems. The testing used a higher concentration of the OxiClean system, longer soak times (24 hours), and comparable systems: **Mudzyme™ C-HT system** for cellulose and Mudzyme S/X system for xanthium.

Simulated filter cakes were tested using both the increased OxiClean concentration and added soak time, and were then exposed to the acid blend. Additional filter cakes were soaked for 24 hours in Mudzyme C-HT and Mudzyme S/X, followed by exposure to the HCl blend. Based on the test results, the operator decided to use the additional Mudzyme system instead of just increasing the amount of the OxiClean treatment.

On well no. 2, the Mudzyme C-HT system was placed in the formation and left to soak for 24 hours before the HCl soak. The acid was left overnight before attempting to inject it into the reservoir. After the treatment, the operator was able to establish a minimum injection rate of 24 MMscf/D with a maximum rate of 29 MMscf/D.

Incorporating the Baker Hughes Mudzyme polymer removal system into the treatment enabled the operator to establish a commercially viable injection rate at given system pressures, and ensured a successful injection program.

Challenges

- Low bottomhole pressure and high permeability
- Polymer-based drilling fluid with calcium carbonate as lost circulation material
- Severe-polymer damage near wellbore
- Lost injectivity at pipeline supply pressure

Results

- Significantly reduced the skin
- Increased injectivity at lower pressures and higher rates
- Combined Baker Hughes Mudzyme and OxiClean systems
- Removed the near wellbore polymer damage
- Enabled the HCL acid to react with the calcium carbonate LCM
- Met operator objectives for injection rates