Baker Hughes

Case study: West Texas

CRO381 corrosion inhibitor delivered cost savings and production boost in WAG tertiary oil recovery project

A major producer in West Texas operated a tertiary recovery water-alternating-gas (WAG) project in which the gas cycle injects a mixture of approximately 8% H_2S and 92% CO_2. The high fluid level wells in this CO_2 flood were being treated weekly with very large displacement treatments for corrosion inhibition. These bullhead treatments typically consisted of three gallons of corrosion inhibitor flushed with 70 bbls of produced water. Most wells lost production for a few days after treatment before stabilizing. The producer wanted to identify an alternate means of getting effective downhole corrosion inhibition without the associated production losses.

The wells were typically about 5,000 ft deep with a bottomhole temperature of 90 to 100°F (32 to 38°C). The wells produced 30 to 60 barrels of oil per day (BOPD) with a water cut of approximately 95%. The brine salinity was approximately 80,000 ppm dissolved solids. The CO_2 content in the produced gas was around 60%, depending upon WAG breakthrough points.

Baker Hughes representatives met with the customer to consider corrosion treatment options. After discussing riskreward considerations, it was agreed that a squeeze treatment program using Baker Hughes CRO381 corrosion inhibitor could help achieve the customer's objectives of minimal production upsets with good corrosion protection.

An economic analysis indicated that a corrosion inhibitor squeeze would need to last for 60 days to equal the cost of the bullhead treatments (pump truck cost and inhibitor cost only). To validate the concept, a three-well implementation plan was cooperatively devised. The plan involved initial treatment of the first well, followed 60 days later by treatment of the other two wells.

This was done to assess the initial inhibitor return and performance profile and to confirm no negative formation impact from the squeeze treatments. Inhibitor performance and ultimate squeeze life was determined via the use of corrosion coupons, inhibitor residuals, and CIDs.

The squeeze treatments consisted of pumping two drums of Baker Hughes CRO381 corrosion inhibitor diluted in 25 barrels of lease crude oil into the well and displacing with enough water to achieve a six foot radial displacement of the inhibitor pill around the well bore. The average squeeze life for the three trial wells was determined to be more than 150 days, or over twice the necessary duration for economic viability. On a chemical treatment cost basis, the squeeze program resulted in a total annual savings of almost $20,000 USD. More importantly, the wells did not have to recover from the weekly displacement treatments. This translated to an increased production from the wells by a total of almost 80 BOPD or 29,000 barrels of oil per year.

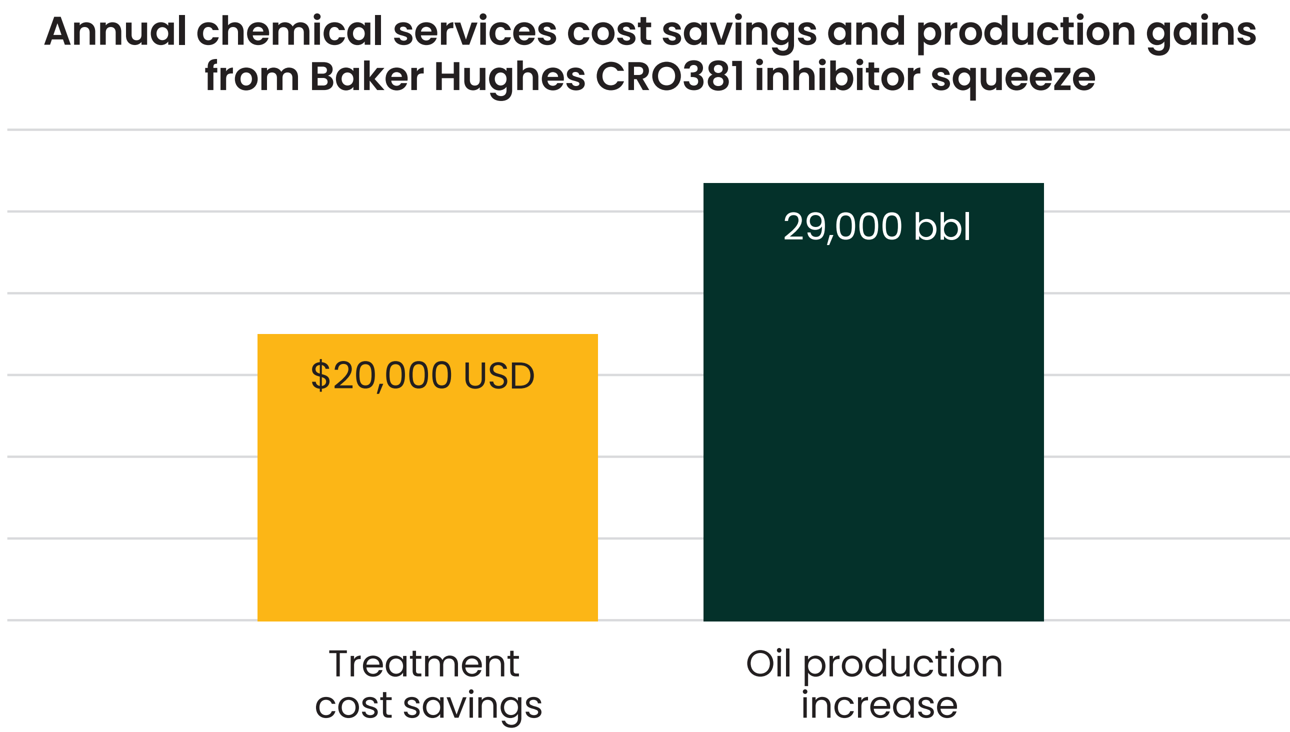
As a result of this success, the program was expanded to include most of the problem wells in the field.

Challenges

- Major producer in West Texas
- Water-alternating-gas (WAG) project
- Needed downhole corrosion inhibition without production losses from large displacement treatments

Results

- Applied recommended CRO381 corrosion inhibitor squeeze treatment
- Achieved double the average squeeze life for three trial wells with no resulting formation damage
- Eliminated the need for weekly displacement treatments with associated downtime


Annual chemical services cost savings and production gains from Baker Hughes CRO381 inhibitor squeeze
$20,000 USD
29,000 bbl
Treatment cost savings
Oil production increase