Baker Hughes

Case study: Kuwait

K-1 cast iron cement retainer proved durability during 13 squeeze jobs, saved rig time, $50,000 USD

An oil-producing well in the Al-Ahmadi field with a third-party packer experienced total fluid losses after failing the 5-in. casing test. This impacted differential pressure and the packing element sustainability was called into question after a third failed squeeze job. Debris had accumulated in the mechanical setting tool due to the stinging in and out after multiple squeezes. The sealing element within the cement retainer and mechanical setting tool also began to fail after multiple injectivity tests. With failures mounting, the operator reached out to Baker Hughes for a solution to permit a successful squeeze operation.

Baker Hughes recommended the **K-1™ cast iron cement retainer**, a tool designed to function as a drillable squeeze packer. After cementing, it acts as a plug, trapping the squeeze pressure on the cement below the retainer and isolating the newly cemented area from the hydrostatic pressures above the cement retainer.

The K-1 retainer is engineered to withstand a high temperature rating up to 400°F (204°C) by using a durable 90-70-90 packing element. The two-way valve feature ensures the final squeeze pressure is held by picking up or stinging out of the stinger, thus closing the valves.

Preparing the project

Based on the fluid loss levels, Baker Hughes engineers performed hydraulic calculations where the differential pressure was observed to be lower than 10,000 psi (68.9 MPa), yet still within the element pressure ratings.

To ensure all scale and debris removal from the casing, field personnel ran a scraper prior to picking up the cement retainer.

Performing the job

The 5-in. K-1 retainer was deployed into the 5-in. casing to a depth of 1,295 ft (394 m). While the stinger was in the setting tool, a pressure test with high fluid loss cement (15.8 ppg) was conducted to 900 psi (6.2 MPa) to verify both the sealing integrity of the cement retainer and the pressure would hold prior to the cement job. This test failed as did the next seven. Despite the repeated failures, the K-1 retainer showed no signs of diminished capacity.

An additional five attempts to perform a successful cement squeeze job were conducted. Frustrated after a total of 13 failed squeeze jobs and injectivity tests, the operator pulled the cement retainer and ran another one into the wellbore. After two squeeze jobs, the well regained fluid level and passed the injectivity test.

Executing flawlessly

Conventional cement retainers require the operator to pull them out of the hole, often after a single use, no matter if the wellbore passed or failed the

Challenges

- Ensure well integrity by performing a casing test
- Clean 5-in. casing of scale to ensure higher flow rate production
- Eliminate fluid losses

Results

- Sustained 13 squeeze jobs and injectivity tests through the 5-in. cement retainer
- Circulated debris with no complications
- Avoided multiple deployments of new cement retainers, saving at least 48 hr and $50,000 USD
- Experienced no health, safety and environmental (HSE) issues NPT

pressure test, and deploy a new one. Each time a single-use cement retainer is pulled out of the hole, operators incur nonproductive time (NPT).

The Baker Hughes K-1 cast iron cement retainer sustained thirteen squeeze operations and injectivity tests—stinging in and out against the sealing element within the tool—without being pulled. This durability saved the customer a minimum of 48 hours of rig time, approximately $50,000 USD by optimizing the operation with the K-1 retainer, and validated the K-1 retainer as a crucial component to cure critical losses.

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