By Marc Durkee, Matthew Montes, Zeke Peak and Philip Nguyen

HOUSTON—ConocoPhillips has saved $2.2 million in cleanout expenses and equipment-maintenance costs on 22 wells in its South Texas production area by treating proppant packs and formations with epoxy-based or furan-based liquid curable resins (LCRs) conveyed by coiled tubing or jointed pipe. The epoxy resin is applicable from 200 to 300 degrees Fahrenheit while the furan resin can be used from 275 to 550 degrees F.

The treatment consists of a rigless intervention procedure that requires no isolation packers, thereby reducing the time, cost and risk associated with a conventional workover operation. This approach treats the existing proppant in the near-well bore region of propped fractures to reduce or eliminate the current and future production of proppant (and/or formation material) and its related problems.

The treatments are greatly enhanced by the use of pressure-pulsing tools that employ fluid oscillator technology, which emits alternating bursts of fluid to create pulsating pressure waves in the well bore and formation fluids. The pulses help remove well bore damage and enhance fluid penetration.

PROPPANT FLOW BACK

The production of proppant and formation material is a pervasive industry problem that hinders production worldwide. In fact, when examining production losses coupled with resulting expenditures caused by maintenance, equipment repair and replacement, this problem is one of the greatest detriments to an asset’s profitability and the operator’s return on investment.

Proppant flow back can result in a number of costly problems, including:

- Production decreases, especially in mature and marginal reservoirs;
- Excessive damage to downhole pumps and surface production equipment;
- Repeated costly workovers and CT cleanouts;
- Intentionally choking back production to reduce sand production or proppant flow back; and
- Shutting wells in rather than operated them uneconomically at lower production rates.

Typical expenses associated with sand production include slick line at $7,500 a day and CT cleanouts at $95,000 per cleanout (repeat treatments may be required because the problem is not resolved at its source). In addition, separators and flowlines have to be periodically cleaned, and surface equipment such as valves, seats and trim damaged by the “sandblasting effect” of solids flow back must be replaced regularly (twice monthly, on average, at $1,500 per maintenance session). As an example, Figure 1 shows an electric submersible pump plugged with proppant, requiring a costly workover.

FIGURE 1

ESP Plugged with Produced Proppant

Reproduced for Halliburton with permission from The American Oil & Gas Reporter
Of course, another significant cost is the revenue lost from choking back production and shutting in wells during workovers.

To cope with the proppant flow back challenges, ConocoPhillips applied conventional treatments with consolidation fluids as a remedial measure. Early attempts failed to achieve uniform placement of the treatment fluid into the propped fractures because of variable permeability, perforation debris, formation damage in the near-well-bore region, and the high viscosity of many resin materials.

The prevailing philosophy at the time was that a greater injected volume of curable resin fluid would increase the potential for success. However, field evidence has shown that this is not always the case. Conventional curable resins that have been used for proppant flow back control have very high viscosities compared with consolidating treatment fluids. Once placed into the propped interval, the excess high-viscosity resin is difficult to displace or remove from pore spaces by the overflush fluid, which typically has a much lower viscosity. Ineffective displacement of the resin from the pore spaces can result in lost conductivity in the proppant pack or permeability damage in the formation.

Stopping Flow Back

The operator elected to confront proppant flow back at its source using a system of LCR-based treatment fluids precisely placed into propped fractures. The treatment chemicals, conveyed by CT, form a consolidated, highly permeable pack that can withstand the high drawdown associated with hydrocarbon production.

Figure 2 shows a proppant pack treated with the consolidating resins. The LCR treatment provides cohesion between grains without damaging the permeability or conductivity of the proppant pack.

The objective of the treatment is to treat the perforations and proppant placed near the well bore, rather than trying to treat the entire proppant pack in the fractures. The fluid-oscillating pulsing tools produce emissions of alternating bursts of fluid that create pulsing pressure waves within the well bore and formation fluids. These pressure waves can break up many types of near-well-bore damage, helping restore and enhance the permeability of the perforations and near-well-bore area. A CT-deployed stimulation service helps improve chemical treatments such as matrix acidizing, scale inhibition and remedial sand/proppant control.

Since most of the wells are not completed with 180-degree phasing perforations, not all perforations are aligned with the propped fractures. The nonaligned (or out-of-phase) perforations located in poorly consolidated formations are prone to producing formation sand during production. Liquid curable resin treatment provides an effective means for sand control by consolidating the formation sand surrounding all the perforations.

If water production is present in addition to proppant flow back, applying the proppant flow back chemicals can be preceded by a treatment stage featuring a permeability modifier that impedes the flow of water through the reservoir and enhances the flow of hydrocarbons. Using fluid oscillator tools creates a downhole fluidic wave that forces fluid injection across the treatment interval into the surrounding matrix to help assure good penetration of both the water-control agent and the LCR.

Treatment Procedure

The chemical treating fluids used in
the process, when properly deployed, offer no obstruction to the well bore or completion and are suitable to be placed in multiple intervals in one treatment operation. The first step in the process consists of cleaning the well and removing any fill to below the lower-most producing interval. A pressure-pulsing tool is then installed on the bottom of a CT (or jointed pipe) bottom-hole assembly, and the CT is deployed into the well to the lower-most producing interval.

A preflush displacement fluid is pumped through the pulsing tool and into the producing interval. The pulsing action is essential and necessary to aid in flushing away debris or fines in the pack. This preflush fluid cleans the proppant surface and prepares it to receive the LCR. The CT annulus is closed during this process. Once the lowest zone is preflushed, the BHA is moved upward across each producing interval in the well bore and the preflush treatment is repeated.

Once at the top of all producing intervals, the LCR is then pumped through the pulsing tool, directly adjacent to the producing interval being treated. The pulsing action helps ensure proper distribution of the LCR into the proppant pack placed near the well bore. The CT is run back down the hole and the consolidation step is replicated at each producing interval down to the lower-most interval.

With the BHA now at the bottom of the well again, a final post-flush fluid is displaced and injected through the pulsing tool and into each producing interval to remove excess LCR. This process is repeated as the CT is withdrawn until it reaches the uppermost producing interval. The CT is removed from the well with the CT/casing annulus still closed, and a solution is injected through the CT to clean the equipment.

The final step is to leave the well shut in for at least two hours, and sometimes up to 48 hours, depending on the bottom-hole temperature of the well.

**Immediate Results**

The process has produced immediate and long-term results in the South Texas wells. It successfully eliminated proppant flow back in more than 90 percent of the treatments, allowing stabilized production without routine well bore clean-outs and surface equipment replacement. Production has been restored in treated wells, reducing lost production time and increasing gas production. By reducing operating expenditures, the process has accelerated profitability and the return on investment for the operator.

Figures 3 and 4 illustrate the production
increases from two of the 22 wells that were treated. The well in Figure 3 was treated in January 2008, and had not produced since July 2007. Production immediately increased to 200 Mcf a day following treatment, and production was still increasing. The well in Figure 4 was treated in July 2007, and had been producing less than 10 Mcf/d since January 2007. After treatment, initial production jumped to 350 Mcf/d, then leveled off at 275 Mcf/d, where it continues to produce.

To help assure success, a number of recommendations should be kept in mind when designing LCR treatments. First, the operator must determine the appropriate treating volumes and select the appropriate consolidating treatment fluids (including preflushes, consolidating agents and post-flushes). Typically, an LCR solution that can provide an unconfined compressive strength of at least 50 psi will be required in the remedial proppant treatment.

If jointed tubing and a packer are used, it is important to ensure that the packer is unseated and pulled out of the well slowly to prevent swabbing of the treatment fluid from the propped fracture back into the well bore. In addition, a positive pressure should be maintained while removing tubing from the well, as well as during well bore shut-in to cure the consolidating treatment fluid.