ESP’s used in a non-traditional role helped profile production in a carbonate oilfield to unlock higher reservoir potential, by Mubarak A Dhufairi, Saudi Aramco, and Paul Docherty, Schlumberger.

**Reliability key to long-term injectivity test**

A COMPLEX CARBONATE OILFIELD in Saudi Arabia required pressure support to sustain production. Saudi Aramco was looking to achieve sustained production using the best-in-class reservoir management practices. The natural drive mechanism came from an aquifer screened from the overlying reservoir by a semi-impermeable tar mat, the geometry of which was relatively unknown, although it was thought to be continuous.

Even so, it was suspected that the tar mat might not be completely sealing. Accordingly, any enhanced oil recovery (EOR) plan using traditional water injection would not be effective.

This article describes a comprehensive, long-term injectivity test whose objective was to characterize reservoir sweep patterns so the optimum number and location of injectors could be determined.

**Well placement was critical**

The initial approach to avoiding the tar mat issue was to geosteer horizontal injector wells so they landed just above the tar mat, in the transition zone between the heavy and light oil. Geologists and reservoir engineers were faced with the challenge of placing the injectors optimally, so injection water would drive crude oil to the producing wells, leaving no movable oil residuals behind.

Before the entire reservoir pressure support scheme was committed, two pilot tests were designed involving a single injector well and six producers located at varying distances and directions. The six producers were intended to be utilized for observation and to monitor the rate of pressure build up with time for each. The producers/observation wells were equipped with downhole permanent and/or retrievable, high-accuracy, long-lasting, battery-powered electronic gauges. It was decided to perform a long-term injectivity (LTI) test with the objective of mapping the sweep pattern and effectiveness of the injection scheme, in addition to qualifying the injection wells placement strategy. Therefore, to obtain supportable results, a massive test was envisioned involving some 3mn bbl of injected water over a 200-day period. Reliability, resolution and accuracy of the downhole gauges were absolutely essential because it was predicted that changes due to injection water could be quite subtle, particularly on the most remote wells in the observation pattern. At the same time, reliability of the injection setup and equipment was equally important. Any breakdowns could completely mask the data transients the engineers were trying to measure.

**Design anticipates tough conditions**

With such reservoir conditions, proper placement of injection wells relative to producing wells was of paramount concern to...
deliver production targets with the highest sweep efficiency model. Robust dual memory electronic gauges capable of withstanding sustained high temperatures for at least 31 weeks were specified. The observation wells were equipped with electronic gauges to monitor reservoir pressure response during the LTI test to confirm reservoir lateral connectivity and possible vertical communication between reservoir layers.

In an effort to aid the overall reservoir characterization, the injection well water profile was planned to identify the contributing zones across the horizontal section and map out the crossflow areas. Furthermore, plans were put to record an II/fall off test, which would include both injection and fall-off tests. Thorough transient analyses were planned including:
- Crossplots of differential pressure vs. logarithmic Horner time
- Crossplots of differential pressures and the square root of time
- Crossplots of logarithmic differential pressure and the log of time
- Crossplots of the log of the pressure derivative and the log of time derivative.

Using derivatives is a traditional technique because the derivative is directly represented by one term of the diffusivity equation, the governing equation for models of transient pressure behavior in well test analysis.

Injection wellbore conditioning

A complicating challenge lay in attempting to return injectors to their original status. During drilling, several of the injection wells experienced lost circulation into natural fractures in the carbonate sequences. These were mitigated by pumping viscous pills of hydroxyethylcellulose (HEC) polymers. As a result, the injection well head pressure (red) and injection rate (blue) are plotted as a function of time. (SOURCE: OTC 21130, Figure 4)

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result, many, if not most, permeable zones had high skin damage. To clean up the damage and restore the original skin effect, acid treatments were pumped. To maintain control over the test data, pre- and post-treatment injectivity tests were run. The skin mitigation program was not without its challenges. Deployed into the lateral using coiled tubing pulled by a downhole tractor, the tools became clogged affecting the control assembly of the tractor. The post-treatment injection measurements, made using downhole gauges deployed on slickline, consisted of pumping 20,000 bbl of treated seawater into the formations; then pausing to conduct a pressure fall-off test. The fall-off test, which took 96 hours, provided vital information regarding the parameters of the injection scheme. Near-wellbore skin, interwell volume and surface injection pressures were determined.

Injection well performance was assessed using Hall-effect plots, based on injection volume and surface injection pressures.

Surface facilities designed for reliability
To avoid further complications, considerable forethought was built-in to the surface system. Basically the plan was to use treated seawater, pumped through a 1.9 mile (3 km) 6-in. diameter pipeline. At the injection well site, two, 2-micron, Vortisand™ sand filters were deployed plus a chemical injection module before the water was pumped into eight, 500 bbl skid-mounted holding tanks. The tanks supplied a set of electrically powered triplex charge pumps providing input to the horizontal above-ground ESP pumping system (HPS). The pumps were energized using a Schlumberger variable speed drive (VSD) powered by three 500 kVA generator sets.

At the intake, duplex diesel-powered pumps drew seawater from a shallow seaside location. These proved to be unreliable and were replaced by duplex submerged ESPs supplied by a motor generator. To assure the LTI test as a reliable source of injection water, the ESPs were determined to be the best solution. The original diesel pumps were retained onsite as backup. System design capacity was 20,000 bbl/day. At the wellhead, the HPS delivered 10,000 bbl/day of filtered, treated seawater at up to 2,500 psi.

During the design and construction of the surface facility, several important lessons were learned:
- Ensure pump intakes were deep, clean and clear of sand and debris
- Ensure pump is not deadheaded into a closed valve
- Address careful alignment of shafts
- Provide a compressor to facilitate system maintenance
- Install tank supports to keep bottom valves accessible

Incorporate additional requirements for:
- Use duplex pumps to provide system integrity and backup
- Provide concrete bases for rotating equipment
- Install a subsurface safety valve to block H2S flowback from well
- Perform full review of generators and VSDs for compatibility

Injectivity tests reduce uncertainties, save money
The pilot injectivity tests were successful. Dynamic data, including pressure transient analysis removed several faults from the geological model. At least 13 injector wells were dropped from the field development plan, largely because uncertainties about the tar mat sealing were redefined. System design issues were successfully resolved to address test goals and result in almost 96 per cent uptime. It was determined that lower powered water injector pumps were required because the injectivity index turned out to be better than expected, and ESPs proved more reliable than diesel-powered pumps. Schlumberger pressure gauge systems and permanent downhole monitors proved both rugged and reliable over the 31-week test period in a hot and highly corrosive environment.

Incorporating data integration with other sources such as drilling data, field production history, available geology and petrophysical analysis from well logs all helped to mitigate risks of skewed interpretation.

PETROFAC AND SCHLUMBERGER announced that their Integrated Energy Services (IES) and Schlumberger Production Management (SPM) divisions respectively have signed a Co-operation Agreement under which these divisions will establish a working relationship to deliver integrated and high-value production projects in the emerging and growing production services and production enhancement market.

Schlumberger and Petrofac have complementary skill sets and execution capabilities. Both have built these through subsurface knowledge, facilities expertise and operational experience in integrated asset management with IES having particular strengths in facilities, engineering and O&M and project management while SPM has particular strengths in subsurface knowledge, production engineering, well construction, and project and asset management. Both companies will deploy their own capital in these production enhancement projects and neither company will seek to book reserves or production. The market opportunity for the collaboration is significant as major resource holders seek to develop discovered low-risk reserves against an industry environment characterized by a shortage of capability and capacity.

Miguel Galuccio, president of Schlumberger Production Management, said: “Schlumberger’s subsurface knowledge, production engineering, well construction and project management services coupled with Petrofac’s surface facility design, installation and ongoing operational field management create a life-of-field approach coupled with a performance-focused commercial model to optimize asset development and overall value.”