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THE TECHNIQUE OF improving formation conductivity through hydraulic fracturing has proved beneficial to oil and gas producers for more than five decades. During this period, significant technology and technique improvements have been introduced that make the practice more cost-effective, more productive in terms of ultimate hydrocarbon recovery and less time-consuming. Still, the practice of hydraulic fracturing has only recently been introduced offshore.

On land, the general availability of large open areas contiguous to the well site enables large accumulations of pump trucks, water tanks and sand trailers along with all the interconnecting piping. If necessary, frac ponds can be dug to accommodate large volumes of frac water. Space is always at a premium with offshore applications. Fortunately, two developments have made the practice of offshore hydraulic fracturing more palatable to operators: deployment of purpose-built stimulation vessels, and the ability to use seawater to mix stimulation treatments. The vessels are completely self-contained, and have all the pumping and blending equipment onboard, along with large tanks that supply frac fluid, proppant and associated chemicals. They generally connect to the rig or platform with flexible, high-pressure hoses and to the wellhead with a portable treatment tree. This makes offshore stimulation very convenient.

Nevertheless, employing a large, state-of-the-art treatment vessel is non-trivial in terms of cost and scheduling. Accordingly, when ENI Congo wanted to attempt to rejuvenate a previously abandoned low permeability oil bearing reservoir in a relatively marginal field, the perceived risk and cost discouraged use of such a vessel, even if availability issues were resolved.

Previous experience dims hope for D sand

Discovered in 1998, the Foukanda Marine Field lies about 52 km to the west of the city of Pointe Noire, Congo. Average water depth is about 100 m. Multiple overlying reservoirs were discovered, but one reservoir in particular proved problematic. The D reservoir had been completed in 2001, but due to poor reservoir characteristics the reservoir was abandoned. The well was completed in the B4 and B7 reservoirs. Over the next six years, six producing wells were drilled and completed at Foukanda, five in the B4 and one in the B7 reservoirs. Three injector wells were also drilled, and completed: two in the B4 and one in the B7. By 2007 Foukanda was producing about 3,000 to 3,500 bopd.

A perfect case study emerges

About 20 km south of Foukanda, the Kitina Field experienced success using hydraulic fracturing to improve its productivity. Treating Kitina wells in May of 2007 proved the possibility of obtaining economic rates from a marginal reservoir. Because of the success achieved at Kitina, the engineers decided to attempt to rejuvenate the abandoned Foukanda D reservoir using the technique. Several attempts to produce from such low permeability, high oil reservoirs were attempted in the past, but the development was temporarily abandoned due to uneconomic rates and poor production.

Typically, hydraulic fracturing is a remedial technique used to stimulate sub optimal wells. As a result, stimulation experts must start with the constraints of the well and reservoir problems that precipitated the stimulation decision in the first place. But at Foukanda, the D reservoir was in the early conditions. Accordingly, the engineers could design the well, the completion and the stimulation up front. Starting with a blank slate, they benefited from the synergies that come when drilling, completion and stimulation engineers can work together on a project from the outset.

The project was not without risk. Because Foukanda D was an untapped reservoir, little foreknowledge was available to the team. Accessing the reservoir required a high-cost long reach well, without any shallower, fall-back target reservoirs to complete in, should the well fail to produce. Inability to deliver a successful completion would likely result in reserves de-booking and abandonment of the entire D reservoir.

Three possible targets beckoned

The Foukanda D sand consisted of three elements, the D1, D2 and D3 in a faulted anticline. Each sand had a separate water drive. Originally, the plan was to drill a near-vertical well through the D reservoir and fracture the D3 by itself, followed by simultaneous fracturing of the D1 and D2. But the stimulation engineers suggested a bolder approach, albeit with more promising potential. They wanted to drill a horizontal penetration of the three sands.

Figure 1. Vertical well option (left) is compared with horizontal well option (right). [Source: SPE 119140 Fig 6]
followed by individual stimulation using a multi-stage fracturing technique (Fig. 1).

The space problem was solved because the operator was able to utilise a tender barge which had plenty of deck space as well as in-hull tanks to hold the gelled frac fluid. 68,182 kg of proppant was stored in two gravity silos on deck with another 45,682 kg in bulk sacks on deck that could be accessed using a pneumatic discharge hose. Four skid-mounted frac pumps were connected to provide a total of 5,500 hydraulic horsepower at 20 to 30 bbl/min. By utilising this equipment costs were minimised and maximum flexibility was assured. The barge was necessary to support drilling operations while also providing a platform for the fracturing equipment.

**Simulation assured proper planning**

Using numerical simulator software, several different scenarios were tried and tested to determine the optimal approach. Because the Foukanda Field was borderline economical, the simulation provided valuable insight on the most potentially profitable solution. Engineers were able to plan fracture spacing, depth and height. The objective was to make multiple transverse fractures that would not interfere with one another, while providing good reservoir conductivity and avoiding geohazards such as nearby aquifers.

The simulation allowed the engineers to make another very important determination. Experience told them that every fracture reaches a point where further deepening yields only incremental benefits. By experimenting with different designs, they were able to zero-in on the optimal fracture length (Table 1).

<table>
<thead>
<tr>
<th>Fracture Length (m)</th>
<th>Start up Fold of Increase</th>
<th>After 1 Year Fold of Increase</th>
<th>5 Year cumulative Fold of Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>30 m</td>
<td>4.2</td>
<td>2.5</td>
<td>+114%</td>
</tr>
<tr>
<td>60 m</td>
<td>5.5</td>
<td>3.0</td>
<td>+134%</td>
</tr>
<tr>
<td>90 m</td>
<td>6.4</td>
<td>3.2</td>
<td>+145%</td>
</tr>
</tbody>
</table>

With these data, it was determined that after 2060 m further lengthening of the fracture yielded marginal increases in production potential. The job was planned accordingly. The simulation also allowed confirmation of the decision to drill a horizontal well with a three-stage fracture treatment as opposed to a vertical or slightly-deviated well with a two-stage treatment. In this case, the difference between the choices was only about 10 per cent higher recovery factor for the horizontal, three-stage fracture well, but it was chosen anyway because it promised better area coverage of the reservoir and thus reduced the risk of failure.

The two-fracture vertical well treatment also offered very little room for error. Fractures are known to propagate along a plane parallel to the plane of maximum horizontal stress. Accordingly, it is important that the well be drilled on a complementary trajectory to the stress planes and Furthermore, that it be perforated along the desired frac plane to avoid near-wellbore tortuosity that can impair the fracture’s ability to propagate to its designed length. With the vertical two-stage approach, everything would have had to be perfect for the stimulation to achieve its design objectives.

Going ahead with the horizontal well with multi-stage treatment proved to be the right choice, because it allowed flexibility to add or subtract stages as indicated during the treatment process. As it turned out, a stage had to be aborted due to mechanical difficulties, but the remaining stages proved to be successful.

**Final plan offered the best advantages**

Since all the planning was conducted before the well was spudded, each stakeholder had a say in the final design. This took maximum advantage of the synergies offered when three sets of eyes look at a complex problem, each from their own perspective. The final design involved drilling a near-
Table 2. Actual results of multistage fracture treatment

<table>
<thead>
<tr>
<th>Plan Stage No.</th>
<th>Planned depth MD (m)</th>
<th>Actual depth MD (m)</th>
<th>Actual depth TVD (m)</th>
<th>Frac length (m)</th>
<th>Frac top depth TVD</th>
<th>Frac bottom depth TVD</th>
<th>Dimensionless conductivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2620</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2</td>
<td>2420</td>
<td>2481.9</td>
<td>1626.0</td>
<td>59.8</td>
<td>1592.9</td>
<td>1653.6</td>
<td>7.17</td>
</tr>
<tr>
<td>3</td>
<td>2220</td>
<td>2343.9</td>
<td>1602.0</td>
<td>54.4</td>
<td>1570.5</td>
<td>1625.4</td>
<td>3.40</td>
</tr>
<tr>
<td>4</td>
<td>2220</td>
<td>2259.4</td>
<td>1588.0</td>
<td>23.2</td>
<td>1579.1</td>
<td>1594.8</td>
<td>1.40</td>
</tr>
</tbody>
</table>

Despite having to forgo placing two fractures in the lower D3 sand member, the stimulation was deemed successful. Pumping was curtailed at the discretion of the operator during the final stage treatment because frac height was deemed to be nearing an aquifer lying just above the Foukanda D reservoir. The fourth stage frac sleeve and its isolation packers were simply left where they spaced out, up in the 9 5/8-in tailpipe and the frac port was never actuated.

Before the main frac treatment was pumped, a breakdown injection test was performed using 100 bbl of linear fluid to determine the fracturing initiation pressure. As the pumping rate was varied from one bbl/min to 20 bbl/min the pressure was monitored. The fracture was observed to initiate at four bbl/min and 4,000 psi (1,500 psi at surface). Closure pressure was picked at 3,500 psi.

Subsequently, a mini-frac test was conducted using 240 bbl of a 16 kg gel mixture pumped at 20.7 bbl/min. A step-down test was conducted. Then post-treatment pressure decline was observed for one hour. Bottom hole initial shut-in pressure was found to be consistent with the previous breakdown injection test. The two pre-treatment tests allowed final adjustments to be made to the pumping schedule prior to execution.

During the pumping of the second stage, there was no clear indication that the frac sleeve had opened, so the breakdown and mini-frac tests were repeated. In fact, the sleeve had opened. Appropriate adjustments were made to the pumping schedule and the treatment continued. The second treatment was curtailed before the design frac length was reached because the frac top was nearing the D-sand top and an aquifer that lies above it. Nevertheless, fracture conductivity greater than three was achieved. As previously noted, the third and final stage was curtailed for the same reason (Fig. 3).

**Post treatment results were spectacular**
Post-frac start-up rate for the Foukanda 109 well exceeded 3,000 bpd. A year later, the well was making 1,500 bpd. This represents 33 per cent of the entire Foukanda Field production. The well produces naturally and to date has achieved a 120 per cent rate increase. Despite the difficulties encountered, the chosen approach was deemed a complete success. Horizontal transverse fractures were achieved, using a technique that permitted well-site adjustments to the pumping schedule. The interdisciplinary approach to well construction and completion was beneficial and fostered close collaboration between operator and service personnel. The project was designed based on reservoir input rather than pre-constrained well conditions. The close spacing of the isolation packers proved very effective in correctly spacing the fractures, and did not have any observable negative effect on production rates. Future such treatments are planned for Foukanda wells.