Abstract

In their natural state, most gas wells in the Middle East do not produce at their optimum level. This is mainly attributable to formation tightness or near-wellbore damage caused by drilling operations; however, a properly designed and executed stimulation program can enable more commercial gas production rates at higher flowing wellhead pressures (FWHPs). For this reason, and others, stimulation jobs (e.g., hydraulic fracturing and matrix acidizing) are common completion operations in the Middle East.

In recent years, stimulation technologies have witnessed major advances, as their use has been the main driver for production from tight reservoirs worldwide. This paper outlines eight new stimulation technologies that have been recently deployed in a major gas field in the Middle East. In addition, the paper looks at candidate selection, the main characteristics and benefits of the technologies, and post-treatment results.

Overall, the production results from the use of these technologies have been very positive and impressive, and the forecast is that their implementation will grow considerably over the coming years. The value of these new technologies will become even more significant as our industry accelerates the development of unconventional resources.

Introduction

The rapid growth of the world’s population motivates companies in the energy sector to make major investments in identifying, developing, evaluating and implementing high-end technologies that will support increases in energy supplies. One energy source that is currently in high demand is natural gas. Within the Saudi Arabian domestic market, the uses of natural gas include heating, cooling and cooking. In the industry, natural gas applications span a wide spectrum, such as plastic manufacturing and metal treatment. Additionally, natural gas has been used efficiently as an advantageous energy source in electricity generation, engine fuel, fuel cells, oil field operations, protein synthesis and petrochemical products’ manufacturing. Accordingly, petroleum companies that are producing natural gas are on the lookout for new tools, processes and equipment that will optimize gas field development and production.

At the top of the list of technologies for optimum production come technologies related to the stimulation domain. These technologies are used mainly to either matrix acidize a well or hydraulically fracture it. The selection of the stimulation operation type depends on reservoir conductivity and mechanical properties, such as in-situ stress and Young’s modulus.

This paper discusses eight new stimulation technologies that have been introduced in a major gas field in the Middle East, Field-A, to boost productivity in the challenging environment of the field. Challenges of the field include low porosity and permeability. The high temperature and pressure of the field only adds more obstacles.
In addition, some parts of the reservoir are highly heterogeneous and significant variation in porosity and permeability is encountered both areally and vertically. The reservoir properties vary between wells and with the same well at different depths, Fig. 1.

The new stimulation technologies deployed in Field-A are as follows: multistage fracturing (MSF), selective stimulation using a temporary chemical plug, metal-based fracturing fluids for high-pressure/high temperature (HP/HT) formations, polymer-free fracturing fluid, carbonate degradable acid diversion, mixing and pumping on-the-fly, organic clay stabilizers and flow-channel fracturing process.

New Stimulation Technologies Deployed in Field-A

This section presents the main characteristics and benefits of the technologies, candidate selection and post-treatment outcomes.

Multistage Fracturing

MSF completions have been field proven to improve well productivity in tight formations\(^1\), \(^4\). MSF technology enables multiple hydraulic fracturing of open hole completions, Fig. 2. During pumping, balls are dropped from the surface to shift each sliding sleeve in the open position and isolate previously fractured stages, Fig. 3. This mechanical diversion allows for precise fluid placement, complete zonal coverage and, ultimately, a higher recovery factor. This technology is applicable for both carbonate and sandstone formations.

Fig. 2. Multistage technology targets the various zones of the formation.
Candidate Selection

MSF works optimally in wells drilled in the minimum stress direction, resulting in transverse fractures. As MSF technologies offer mechanical diversion, they work well in long heterogeneous intervals with fracturing ports placed across more porous sections of the productive interval6.

Implementation and Outcomes

To date, a total of 40 wells have been completed with MSF completion technologies with a success rate of 87.5% in post-treatment production rate exceeding the target gas production rate. Figure 4 shows the post-treatment stabilized gas production rate for six sample wells that have been completed with MSF technologies. The post-treatment stabilized gas production rates indicate that MSF wells are better producers than offset non-MSF wells.

Selective Stimulation Using a Temporary Chemical Plug

This technology utilizes a nondamaging, temporary cost-effective chemical plug (Photo 1) and coiled tubing (CT) to stimulate zones of interest selectively in the presence of other zones. The chemical plug is used to provide temporary isolation while the CT places the stimulation treatment into the target zone. This application enables a more flexible movement for CT and easier removal of the plug once it is not needed, using common breakers like acids and oxidizers6,8.
Candidate Selection

This technology was successfully applied in Well-B1 with the objective of stimulating a damaged lower zone in the presence of a previously stimulated high permeability zone. Selective stimulation using a temporary chemical plug was suitable in this case as the well completion configuration was not a monobore and there was a space of 560 ft between the two zones. Also, laboratory analysis carried out in a HP/HT consistometer had confirmed that the chemical plug was stable at Well-B1 bottom-hole conditions (5,600 psi and 242 °F), Fig. 5.

Implementation and Outcomes

During the treatment execution, the chemical plug was conveyed using CT. A setting time of 6 hours was allowed for the chemical plug to solidify. Next, the CT was run through the plug, Fig. 6, and successfully pumped the stimulation treatment into the target zone. Finally, the CT was pulled out of the hole while pumping 10% hydrochloric (HCl) acid to dissolve the temporary chemical plug. Table 1 shows a comparison between the Well-B1 pre-stimulation and post-stimulation production results. In terms of production, there was an increase of 93%, indicating a successful implementation of the technology.
**Fig. 6.** Weight indicator showing a decline in CT weight; indicating a semi-solid gel plug.

<table>
<thead>
<tr>
<th>Pre-stimulation Production</th>
<th>Post-stimulation Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas rate (MMscfd)</td>
<td>Gas rate (MMscfd)</td>
</tr>
<tr>
<td>FWHP (psi)</td>
<td>FWHP (psi)</td>
</tr>
<tr>
<td>3</td>
<td>5.8</td>
</tr>
<tr>
<td>1,500</td>
<td>1,830</td>
</tr>
</tbody>
</table>

**Table 1.** Post-stimulation results compared to pre-stimulation results

**Metal-based Fracturing Fluids for HP/HT Formations**

Metal-based fracturing fluids provide long-term thermal stability from the zirconium cross-linker, Fig. 7. At the same time, they do not sacrifice early time viscosity that is critical for the creation of fracture width by eliminating the traditional shear sensitivity of metal cross-linked fracturing fluids through incorporating borate crosslinker. Also, metal-based fracturing fluids are compatible with multiple clay stabilizers. The maximum working temperature for metal-based fluids can reach up to 400 °F.

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**Note:** The diagram shows a graph with various lines indicating different parameters such as CT pipe weight, CT pressure, wellhead pressure, and others. The graph illustrates a scenario where CT weight is reducing, indicating the presence of a semi-solid gel plug.
Candidate Selection

Metal-based fracturing fluids are designed for fracturing HP/HT formations, where conventional borate cross-linked fluids would not be effective due to their high degree of sensitivity to the high formation temperature and pressure, Fig. 8. Accordingly, metal-based fracturing fluids were selected for fracturing HP/HT formations in Field-A.
Implementation and Outcomes

This new fracturing fluid technology has been successfully used in proppant fracturing two HP/HT (8,500 psi and 340 °F) gas wells. Table 2 shows the fracture parameters that have been achieved after the fracturing operation for the two gas wells. Table 3 shows the stabilized flow condition for the two wells.

<table>
<thead>
<tr>
<th>Well Number</th>
<th>Half-Length (ft)</th>
<th>Height (ft)</th>
<th>Width (in)</th>
<th>Effective Conductivity (md-ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well-C1</td>
<td>245.5</td>
<td>216.8</td>
<td>.233</td>
<td>3,665</td>
</tr>
<tr>
<td>Well-C2</td>
<td>197</td>
<td>103</td>
<td>.64</td>
<td>6,255</td>
</tr>
</tbody>
</table>

Table 2. Fracture characteristics for Well-C1 and Well-C2

<table>
<thead>
<tr>
<th>Well Number</th>
<th>Stabilized Production Rate (MMscfd)</th>
<th>FWHP (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well-C1</td>
<td>16</td>
<td>4,820</td>
</tr>
<tr>
<td>Well-C2</td>
<td>21</td>
<td>5,275</td>
</tr>
</tbody>
</table>

Table 3. Stabilized flow conditions for Well-C1 and Well-C2

Polymer-free Fracturing Fluid

Polymer-free fracturing fluid has three main characteristics that give it advantages over other fracturing fluids. First, it creates less damage as it does not contain polymer, Photo 2. Second, it enhances the fracture geometry by creating deeper fractures while controlling height growth, Fig. 9. Third, it simplifies wellsites logistics as it requires fewer additives, making it easier to mix and pump as opposed to other fracturing fluids10.

Photo 2. Comparison between a proppant pack that has been treated using polymer-free fluid (left) and a proppant pack that has been treated using polymer-based fluid (right) under the same condition.

![Fig. 9. VES polymer-free fluid increases effective fracture half-length without compromising proppant transportability.](image_url)

Candidate Selection
The polymer-free fracturing fluid was implemented in only one gas well (Well-D1 in Field-A) while the benefits of the fluid were examined and analyzed. Well-D1 was selected because of its narrow productive interval located between two water-bearing zones, Fig. 10. Since it was critical to control the height growth of the induced fracture to avoid penetrating any of the two water zones, polymer-free fracturing fluid was a perfect fit as it has been field-proven for improving the fracture geometry\textsuperscript{11,12}.

![Fig. 10. Logs versus target zone for Well-D1.](image)

**Implementation and Outcomes**

The fracturing operation was successfully executed using polymer-free fracturing fluid technology. The average pumping rate was 39.4 barrels per minute, and the maximum treating pressure was 10,693. Post-treatment analysis of the fracture characteristics was performed to compare the actual parameters achieved after the fracturing operation to the pre-treatment expectations, Table 4. Figure 9 shows Well-D1 nodal analysis for pre- and post-stimulation conditions, presenting a positive productivity increase.

<table>
<thead>
<tr>
<th>Category</th>
<th>Half-Length (ft)</th>
<th>Height (ft)</th>
<th>Width (in)</th>
<th>Average Conductivity (md-ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Design</td>
<td>220</td>
<td>151.5</td>
<td>.125</td>
<td>4,741</td>
</tr>
<tr>
<td>Achieved</td>
<td>437.1</td>
<td>82.4</td>
<td>.190</td>
<td>1,877</td>
</tr>
</tbody>
</table>

*Table 4. Fracture characteristics: design versus achieved*

![Fig. 11. Nodal analysis for Well-D1.](image)
Carbonate Degradable Acid Diversion

Carbonate degradable acid diversion technology incorporates dissolvable fiber and nondamaging acid. This HCl acid-based system offers stimulation and then flow restriction for diversion. The interlocking fiber network blocks fluid during the stimulation job yet dissolves completely with time (6-8 hours). The network can be bullheaded or deployed with CT, and the carbonate degradable acid diversion system can be used in open hole or cased hole completions for many applications.

Candidate Selection

In Field-A, the acid degradable diversion system candidates were mostly wells drilled in highly slanted layers, and naturally fractured carbonate reservoirs exhibiting a contrast in high permeability and porosity. The technology was applied in more than 30 wells.

Implementation and Outcomes

During the treatment execution, the bottom-hole pressure trends clearly showed indications of effective diversion even in HP/HT carbonate naturally fractured gas reservoirs whenever the acid degradable diversion system entered the formation, Figs. 12 and 13. This technology has been applied in new developments and existing gas producers in Field-A, with results showing substantial pressure responses and excellent gas production performance, Figs. 14 and 15.
Fig. 13. Well-B treatment plot.

Fig. 14. Pre- and post-stimulation results; gas production.
Mixing and Pumping on-the-Fly

The mixing and pumping on-the-fly technique involves mixing the fracturing slurry continuously using hydration units as the treatment is pumped into the well to reduce cost and improve efficiency. In addition, the on-the-fly technique reduces the exposure of personnel to chemicals, bacterial contamination and slurry waste. The field application of this technique demonstrated excellent job quality and fluids were within specifications\textsuperscript{14}.

Candidate Selection

In Field-A, the mixing and pumping on-the-fly technique was preferred for every fracturing operation because of the benefits outlined earlier.

Implementation and Outcomes

When applied during fracturing operations, the mixing and pumping on-the-fly technique reduced operational time by an average of two days compared to the conventional batch mixing technique. The use of this technique also resulted in a cost saving of $100,000 per stage. Moreover, the fluid treatment leftovers were minimal, making this technique more environmentally friendly and cost-effective.

Organic Clay Stabilizers

Organic clay stabilizers are added to fracturing fluids to mitigate the effects of clay agitation and swelling in formations that are sensitive to water\textsuperscript{15}. Organic clay stabilizers have been introduced in Field-A to replace the common clay stabilizer, KCl powder, to optimize operational time and cost. Organic clay stabilizers are used at a lower concentration than KCl and are compatible with many fracturing fluids. Unlike KCl, organic clay stabilizers can be mixed and pumped by using the on-the-fly technique, resulting in substantial operational time optimization.

Candidate Selection

Organic clay stabilizers were added to the fracturing treatment of wells drilled in water sensitive formations. They were also selected for high temperature formations, where KCl-based stabilizers would fail to be very effective.
Implementation and Outcomes

During the execution of fracturing treatment, organic clay stabilizers can be mixed as liquid, making them suitable for being pumped using the on-the-fly technique. As organic clay stabilizers can be mixed with this technique, they result in substantial operational time optimization and cost reduction. In Field-A, organic clay stabilizers were successfully used downhole where the bottom-hole temperature was 330 °F.

Flow-channel Fracturing Process

This new process removes the dependence of the fracture performance upon the proppant characteristics. This is done by creating open channels inside the fracture, enabling hydrocarbons to flow through the stable channels rather than the proppant, Fig. 16. This optimizes connectivity between the reservoir and the wellbore — resulting in infinite fracture conductivity. With the flow-channel fracturing process, fracture proppant is placed heterogeneously in the form of proppant “pillars” surrounded by open channels. Apparently, there is a lower risk of screen-out using this process.

Candidate Selection

This technology was applied in only one gas well, Well-H, that had been drilled in a consolidated tight formation.

Implementation and Outcomes

The flow-channel fracturing process was successfully implemented in Well-H1. The execution of this new process demonstrated that it consumes 50% less proppant and fracturing fluids compared to conventional fracturing, resulting in faster fluid recovery. After the treatment, Well-H1 was flowing at a production rate of 8.6 MMscfd with FWHP of 1,164 psi, reflecting the success of the flow-channel fracturing process.
Conclusions

This survey of eight new well stimulation technologies provided the following conclusions:

1. Eight new stimulation technologies were successfully deployed to enable and support commercial gas production in the challenging environment of Field-A.

2. Proper candidate selection is an important step for making the most valuable use of new technologies.

3. The right implementation strategies must accompany the right technology to increase the possibility of its success.

4. The value of new and innovative stimulation technologies will become even more significant as our industry accelerates the development of unconventional resources.

References


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**SI Metric Conversion Factors**

- ft x 3.048\times 10^{-1} = m
- in x 2.54\times 10^0 = cm
- lbf x 4.448222\times 10^0 = N
- md x 9.869233\times 10^{-4} = \mu m^2
- psi x 6.894757\times 10^0 = kPa
- bbl x 1.5898\times 10^{-1} = m^3