Rigless Stimulation in Deepwater Field – Case History: Jubilee Field

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Abstract

One of the most common methods for well stimulation includes the use of mobile offshore drilling units (MODU) to pump fluids into the well with the main objective of restoring production or injection. A rig-based well stimulation is an expensive operation and in some cases a separate stimulation vessel is used to store and pump fluids. Economics to justify a stimulation operation may require a number of wells (depending on well productivity) to make the project economically viable. New industry developments in the last few years have made the use of special intervention techniques from vessels relatively popular. However, a riser based system remains the preferred method to intervene/stimulate deepwater wells. Riserless systems are becoming more and more popular but their applications vary from region to region based on water depths, sea conditions, equipment and technical personnel availability.

Since start of production from the Jubilee field, several oil producers had experienced gradual productivity decline with a significant reduction in flowing bottom hole pressure, despite an aggressive pressure maintenance program with water and gas injection. Following the success of previous acid stimulation work carried out off the rig in an attempt to restore productivity, a rigless acid stimulation treatment on the impaired Jubilee wells was proposed. An initial feasibility study was conducted, which indicated that a Rigless stimulation operations using a Multi Purpose Supply Vessel (MPSV) was considered to be a commercially and technically feasible operation. While the primary objective of the rigless stimulation campaign was to increase production, this work also demonstrated that the rigless intervention from the MPSV is a cost effective and technically feasible option for a long term campaign. The operation was successfully conducted using two vessels. Fluids where pumped into the well using 4 x coiled tubing strings deployed in 1,600 m water depth. This paper explains the methodology used for the development of a rigless stimulation campaign in the Jubilee field, offshore Ghana.

Jubilee field

The Jubilee Field is located 132 km southwest of the port city of Takoradi in the West Cape Three Point (WCTP) and Deepwater Tano (DWT) blocks offshore Ghana. Water depth ranges between 1,000 m to 1,600 m. Analysis done after the drilling of two discovery wells in the West Cape Three Points and in the Deepwater Tano contract area, determined that the
wells encountered an accumulation of hydrocarbons that extends across their boundaries. Tullow Ghana Limited ("Unit Operator") is the operator of the Jubilee Field on behalf of the Jubilee Field unit interest owners. The Jubilee development consists of proven subsea concept with wells tied back to FPSO through subsea wellhead, manifold, flowlines and flexible risers. The field has been developed with a voidage replacement ratio (VRR) achievable by water injection. This is to ensure reservoir pressure is kept above the bubble point at all times. Though the initial intended purpose of the associated gas is disposal by injecting up-dip into the reservoir pending the availability of the gas export pipeline by the national gas company, gas injection also provides pressure support to the wells.

**Well Impairment**

Since start-up of the Jubilee field, several oil producers had experienced gradual productivity decline with a significant reduction in flowing bottom hole pressure. A number of studies were carried out to identify the cause of the productivity decline. Initial conclusions pointed towards fines migration problem as the root cause for the loss of productivity. This conclusion was based on analysis done on core and log profiles which showed some thin unconsolidated reservoir sand intervals capable of producing some fines under differential pressure. Also, results from a dead oil bullhead operation on selected impaired wells, provided an additional enforcement of the fines migration theory as the cause of impairment. In addition to fines migration, mineral scaling was also considered due to the self scaling tendency of formation water. However, no water production had been recorded on any of the impaired wells. The organic deposit theory, which was also considered as one of the causes of impairment initially, was discarded as there was no evidence from testing that support this damage mechanism.

Based on this initial analysis, the stimulation treatment was designed to dissolve clay minerals that may be plugging the screen and near wellbore area. The proposed acid formulation was also expected to stabilize the clays further out in the formation preventing further fines migration. The first acid stimulation was performed in 2012. The job was successfully conducted on three wells using a Semi Sub or MODU. In two of the wells the displacement was done with coiled tubing in order to address the fluid diversion challenges. Wellbore re-entry difficulties were experienced in one of the wells treated with coiled tubing, as some obstructions were observed between the upper and lower zones. Samples of the obstruction material recovered showed that the blocking material was scale. This confirmed the initial theory that calcium carbonate scale is one of the primary causes of production wellbore plugging. The sample was tested to verify its reaction with the stimulation formulation fluid which was designed to address fines migration. Results from the test showed that the scale dissolution was less efficient. Based on this new data point, the acid treatment was re-formulated to include 5% HCl and 10% acetic acid as initial pill before the main Organic Clay Acid treatment (OCA). The well was put on production after the OCA treatment and its performance showed poor results when compared with the rates obtained after the initial scale treatment.

The conclusion was a possible reaction of scales still present in the formation with the HF component of the OCA causing calcium fluoride precipitation. The behavior of the well performance demonstrated the evidence of solid material plugging the screens. Production was then restored with a 5% HCl-10% acetic acid system. A second stimulation campaign was done to rectify the production decline on wells previously treated with OCA and also in new wells. The use of the new formulation to address calcium carbonate scale was proven to be successful demonstrating that scale build up is the main well impairment mechanism.

**Rigless Intervention**

An alternative stimulation method was proposed with the aim of performing further acid treatments on other impaired wells at a reduced cost and without the use of a rig, with the additional benefit of freeing up rig time to conduct other critical operations such as drilling and completion. The main objective of the Rigless Intervention was to stimulate wells and increase production while maximizing safety, minimizing environmental hazards and optimizing project economics. For this operation a dual vessel configuration was proposed. The first vessel (Frac Boat) was used for chemical storage and pumping operations while the second vessel (Multi Purpose Supply Vessel – MPSV) was used as a platform for all the Well Stimulation Equipment. The two vessels where connected using a 4” Coflex hose. Two different methods of fluid displacement to the wells were used during the campaign:

- **Subsea Tree Adapter:** For this method an Adapter was fitted to the bottom of the Well Stimulation Tool. Once the WST tool is landed on top of the subsea tree bore, it can be locked in place. The displacement of fluids into the well was done through the subsea tree X-over loop as depicted in the Figures 2 & 3 below
Figure 2. Rigless Stimulation proposal – Adapter option

Figure 3. Subsea Tree flow path – Adapter option
Intervention Choke Insert: For this method the Well Stimulation Tool (WST) was deployed on the sea bed using a mud mat. The production choke was changed out to allow the installation of an Intervention Choke Insert. The displacement between the WST and ICI is done through a jumper hose (Figure 4).

Figure 4. Rigless Stimulation proposal – ICI option

Figure 5. Subsea tree flow path – ICI option
**Well Stimulation System**

The Well Stimulation System (WSS) comprises a series of equipment to allow the safe displacement of fluids into the well. This system eliminates the requirement for a drilling rig/vessel and surface riser. It is deployed, operated, controlled and retrieved from a MPSV, while the fluids are delivered to the well via coiled tubing strings. The components of the system are:

- **Well Stimulation Tool**: This tool provides the interface to the subsea tree to allow safe conduit of fluids into the well. Its main feature is the remote emergency shut down, which is activated acoustically from surface. This allows a well shut-in with a dual mechanical ball valve arrangement and at the same time the hot stabs connected to the tool are ejected. The Zero leak stab design will prevent any fluids loss to the environment;

![Figure 6. Well Stimulation Tool](image)

- **Coiled tubing**: 4 coiled tubing strings were use for this campaign to be able to achieve the desired pumping rates;

- **Flexible hose**: Used to transport fluids between the coiled tubing and the Well Stimulation Tool; and

- **Hot stabs**: Used to couple the flexible hoses to the Well Stimulation Tool. Main features:

**Rigless Intervention Design Methodology**

A number of activities for the qualification of this new technology and its implementation on the Jubilee field took place to ensure the system was fit for purpose:

1. **Flow Model**

   During the rig-based acid stimulation operations, high flow rates were achieved through the X-over loop on the subsea tree. High flow rates were required to ensure fluid diversion at the sand face. Physical diversion techniques were ruled out as all the well candidates have been completed as a Frac Pack completion. Chemical diversion was not feasible due to formation damage concerns with the proposed fluids.

   For the rigless campaign, the reduced ID of the coiled tubing strings created high friction losses and as a result a reduced fluid delivery at the subsea tree. A flow model was conducted to determine the theoretical friction losses through the system. The initial proposal was done to model the fluid displacement through 2 x coiled tubing strings. Results from this study showed that a maximum of 6 bpm can be achieved with this configuration. This was below the 15 bpm requirement. A second flow model was set up with 4 coiled tubing strings (2 x 2” and 2 x 1-3/4”). The new model proved that up to 10 bpm can be achieved. However, as this was still under the 15 bpm required, a full scale System Integration Test (SIT) was recommended to prove the boundaries of the equipment. An interesting result from the model showed a 40/60 distribution due to the different CT geometry (Figure 7).
2. System Integration Test

A full scale System Integration Test (SIT) was conducted to demonstrate the integration of the Well Stimulation System to prove the maximum rate that can be achieved and to understand pressure losses through the system. For this test, all the equipment was installed in a way to represent the proposed offshore installation. Also, the pumping schedule was simulated; however, no chemicals were used on this test, only fresh water. Results from the test demonstrated that a pump rate of up to 15 bpm can be achieved with a 4 CT string configuration, as depicted by Figure 8.

From the rate distribution plots it was established that when pumping through the 4 CT strings, 60% flow will occur in the 2” CT and the remaining 40% fluid will flow through the 1.75” CT, which basically demonstrated the results from the theoretical flow model.
3. Subsea Tree

a. Elastomer Compatibility with Acid: An elastomer test was done to evaluate the chemical resistance of three HNBR seal compound on the subsea tree. The ageing regimes used during the tests were selected to replicate actual pumping conditions and worst case conditions as closely as possible.

Results of the test showed no major concerns. The physical and mechanical property changes are well within the requirements of NORSOK M-501.

b. Subsea Tree Pumping Limitation: A flow restriction was identified in the Annular Porting System (APS) and a Computational Flow Dynamic (CFD) study was commissioned to determine the maximum achievable flow rate through this flow path. The limiting structural interface was the debris catcher. A previous study conducted showed that the restriction generates 15% reduction in the flow coefficient. The flow rate steady state was calculated using the following equation:

\[ C_v = \frac{Q}{\sqrt{\frac{SG}{\Delta P}}} \]

Where \( C_v \) is the flow coefficient, \( Q \) is the flow rate (gpm), \( SG \) the dimensionless specific gravity, and \( \Delta P \) is the pressure drop in pounds per square inch.

Considering a SF of 1.5 the maximum acceptable axial load on the debris catcher corresponds to a flow rate of ~20 bpm, which is above the maximum rate achievable with the Well Stimulation System.

4. Metallurgy Test

Previous metallurgy studies were conducted to prove the compatibility of the coiled tubing and completion equipment with stimulation fluids. For the rigless intervention, a metallurgy test was done to demonstrate the adequacy of the corrosion inhibition package for the Intervention Choke Insert metallurgy, which is the only variation from the rig-based jobs. The maximum allowable corrosion rate was established at 0.05 lb/ft². Results from the test showed that the proposed inhibition in the fluid was adequate to protect the ICI metallurgy for up to 12 hrs.

5. Clashing Assessment

One of the main concerns for the operation was the open water deployment and pumping operations of 4 coiled tubing strings in 1,600 m of water. A CT clashing assessment was set up to model the effect of the subsea currents at different water depths that will create a potential for equipment damage due to clashing. Two different scenarios where considered: CT
disconnected (deployment) and CT connected case (connected to the subsea tree). The maximum critical current for the operations was established and compared with likely sea conditions for the duration of the job.

6. Vortex Induced Vibration (VIV)

A VIV fatigue is one of the potential failure modes on subsea riser systems when exposed to marine currents. The response of flexible structures to the marine current loading results in a multi-frequency vibration that may cause fatigue damage on the structure leading to failure. The objective of this assessment was to determine the maximum marine current that can lead to CT fatigue or failure using established models for riser analysis.

7. Stimulation design

The formation damage mechanism was identified to be calcium carbonate scale at the near wellbore area. Acid formulations used on previous stimulation campaigns showed good results, and in some cases production was restored to original levels. For the Rigless Stimulation the same and proven acid recipe will be used. The following table summarizes the proposed pumping schedule for the Rigless Stimulation:

<table>
<thead>
<tr>
<th>STAGE</th>
<th>FLUIDS</th>
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<tbody>
<tr>
<td>Injectivity Test</td>
<td>Base Oil</td>
</tr>
<tr>
<td>Preflush</td>
<td>NH4Cl / Solvent</td>
</tr>
<tr>
<td>Spacer</td>
<td>NH4Cl</td>
</tr>
<tr>
<td>Main fluid</td>
<td>5% HCl / Acetic Acid 10%</td>
</tr>
<tr>
<td>Spacer</td>
<td>NH4Cl</td>
</tr>
<tr>
<td>Overflush</td>
<td>Base Oil</td>
</tr>
<tr>
<td>Displacement</td>
<td>Base Oil</td>
</tr>
</tbody>
</table>

Table 1. Pumping stages

Stage 1 – Injectivity Test: The main objective of this stage is to determine the injectivity index pre acid stimulation.

Stage 2 – Preflush: The objective of this stage is to remove any heavy hydrocarbon deposits, controlling the wettability of contact surfaces before the main treatment, and preventing or breaking emulsions.

Stage 3 – Spacer: As on the previous stage, ammonium chloride is used to prevent or break emulsions.

Stage 4 – Main Fluid: 5% HCl / 10% acetic used to clean-up the perforation tunnels of any CaCO3 deposits or other carbonate-based scale precipitates, which may be plugging the screens or perforations tunnels.

Stage 5 – Spacer: Ammonium chloride used as a buffer between the main acid treatment and base oil with the aim of controlling any emulsions.

Stage 6-7: Overflush/Displacement: This stage was designed to push the main treatment fluid away from the near wellbore to prevent tertiary reactions and aluminosilicate scaling or precipitations near the wellbore.

Operational Considerations

a. Vessel selection: the MPSV vessel selection was based on the following criteria:

- Technical capacity of the vessel is adequate for the planned stimulation jobs;
- Deck space is suitable for the Well Stimulation System equipment;
- AHC Crane with capacity for the deployment of the Well Stimulation System to sea bed;
- POB capacity is suitable for the required manning levels;
- Availability of the vessel for the project timeframe;
- Vessel with capability to provide field support activities not related to the rigless stimulation operation (inspection, maintenance, repairs, etc);
- 2 x Work class ROV capability; and
- Helideck for offshore personnel transfer
b. Vessel to Vessel operation: After numerous iterations, a side by side vessel operation was considered to be the preferred vessel positioning. The main justification for this proposal is to position the stern of the frac boat ahead of the MPSV aft thrusters.

![Figure 10. Vessel to vessel separation schematic](image)

The proposed vessel separation was based on the bend radius of the Coflexip hose on the frac boat. This didn’t represent a risk for the starboard ROV deployment from the MPSV.

c. Vessel dynamic positioning: The primary positioning system for the MPSV was the Global Positioning Reference System or GPRS. Given the safety critical aspect of the positioning system during the pumping operations, GPRS was deemed to have an incremental risk due to external factors that can affect the signal. Loss of GPRS signal is a common occurrence and with a vessel connected to the subsea tree and 4 coiled tubing strings under pressure a more reliable system was deemed necessary. For this reason a Long Base Line (LBL) dynamic positioning system was set up to provide accurate positioning of the MPSV during the stimulation operations. This required the set up of a new High Precision Acoustic Positioning System (HIPAP) on the vessel and additional ROV dive to set up the transponders on a pentagonal array around the subsea tree on the sea bed.

d. Vessel to vessel positioning: After the Well Stimulation equipment was deployed from the MPSV and “locked” and tested in place, the frac boat was allowed to enter the safe zone. Given the proximity of the two vessels and the fact that during pumping operations the vessels were connected through a Coflexip hose, a dynamic positioning system was required to have the two vessels at a safe distance and prevent collision. The frac boat has it own GPRS positioning capabilities but concerns of the reliability of the system during the pumping operation were still valid. For this reason a relative positioning system was set up on the Frac Boat: Fan Beam. This consisted of a laser beam directed to the main MPSV structure. The Fan Beam computer was set to a pre-determined distance and once this was done the frac boat became a slave and followed the main vessel movements to remain at the pre-determined distance.
e. Data Transmission: MPSV Class restrictions didn’t allow the vessel to be connected to the subsea tree. This prevented a direct link to the tree to control the subsea tree valves or gather pressure and temperature information from the downhole gauges. This information is critical for the operational phase as real time decisions are taken during the job execution based on well behavior during pumping. For this reason, a complex data transmission system was set up between the FPSO, MPSV and frac boat. In addition to this, a real time data transmission link was installed to allow monitoring stimulation operations parameters on remote locations (Figure 12).

f. Subsea Tree Control: For previous rig-based stimulations, the IWOCS has been used to establish electro – hydraulic communication to the subsea tree. Given the lack of availability of an IWOCS system within the project timeframe, a separate system was engineered to allow full control of the well using the existing FPSO infrastructure. The control logic at the Master Control Station was modified to allow the manipulation of valves that are not part of the normal operations but required to be opened/closed for the rigless intervention. Also, downhole pressure and temperature data was acquired at the MCS and transmitted to the MPSV and frac boat using the protocol explained previously.

g. Well Control: THSIP data was available and the operational steps mandated that under no circumstance should the
subsea tree valves be opened at underbalanced conditions. This is to prevent any fluid influx into the CT strings. During pumping operations there was a possibility of pumps malfunction and given the complex set up of communication with the FPSO for subsea tree valve movement there was a risk of fluid ingress into the system. To minimize this occurrence a check valve was located on the frac boat. With the system on positive pressure the likelihood of fluid ingress was reduced to ALARP. The first protocol in case of any emergency was to close the well from the FPSO. The last resort was to activate the Emergency Quick Disconnect feature on the Well Stimulation tool, which closes the well path and ejected the hot stabs. Also, gas influx into the coiled tubing string was considered to be a significant risk. For this reason a choke was included on the surface piping on board the MPSV and the return tank vents were locked in the open position to allow cold venting of gas. Gas detectors were also fitted. During the operations there was no occurrence of gas influx into the coiled tubing or at surface.

h. SIMOPS: this was considered to be one of the main operational risks due to the number of vessels working on the field: FPSO, tankers, 2 MODUs, 1 MPSVs, security vessel, supply vessels, frac boat and seismic vessel. A SIMOPS document was generated to formalize the scope of work and protocol of communications between different disciplines so any variation to the agreed work scope was clearly identified.

Job Execution

A four well campaign was initially planned. The installation of the Well Stimulation Equipment took place after MPSV vessel delivery at Takoradi. Several challenges were experienced during the installation process and this represented the highest NPT through the project. The vessel DP and the newly installed HIPAP system were tested 42 NM offshore. After the vessels system were checked a mock up test was conducted to simulate the operations offshore and identify potential operational improvements. The two vessels where positioned alongside each other and the Cofflexip hose was deployed from the frac boat to the MPSV. The system was connected at surface on a close loop and the lines were pressure tested. No subsea deployment of any tools took place during this phase. A job simulation took place and valuable information and lessons learned were acquired during this test. After the test, the MPSV sailed to the field location and communication was established with the FPSO prior to entering the 500 meters zone. The field support vessel assisted in setting up the LBL transponders before the arrival of the MPSV. Once on location, the Well Stimulation Tool was deployed at the safe handling zone and then the vessel transitted to the subsea tree location using the safe egress path. The deployment of a single coiled tubing string was done using the AHC crane. This operation was repeated until all (x4) coiled tubing strings were lowered and suspended 60 m above the sea bed. The flexible hose and hot stab, secure at the end of the CT string, was manipulated with the ROV and installed on the hot stab ports receptacle at the Well Stimulation Tool. Once all commissioning checks were done, the frac boat was allowed to be positioned alongside the MPSV. The Cofflexip hose was then deployed from the frac boat to the MPSV using the AHC crane. After the hose was secured at the MPSV, the DP systems were checked and the relative DP system (Fan Beam) was established. The FPSO was instructed to open the required subsea valves and the stimulation treatment was performed on the well. Although the complete system was certified to 10k psi, the pumping operations were limited to 8,500 psi to allow enough room for the NRV’s to be set on both the MPSV and the frac boat. All the treatments were done below frac pressure and the flow rates were established to enable good fluid diversion while ensuring surface and bottomhole pressure remained below set limits.

An additional well was added to the list of original wells for the campaign after good initial production results were obtained on the initial two wells. It was also decided to perform this operation using Intervention Choke Insert option on this additional well.
Rigless Stimulation results

Operationally, the campaign was successfully conducted with no safety incidents to report.

The following figure shows the productivity indexes of the wells pre and post rigless treatment. In all the cases the productivity was restored to their initial values.

An increase in rate of more than 25,000 bopd was achieved from the intervention. Figure 14 shows the the restoration of productivity indexes for all the wells treated.

![Figure 13. Offshore Execution](image)

![PRE & POST RIGLESS ACID PRODUCTIVITY INDEXES](image)

![Figure 14. Rigless Stimulation results](image)
Conclusions

This was the first rigless acid stimulation conducted for Tullow and the first rigless stimulation conducted in Ghana. The main objective of the campaign was to restore production on wells facing production decline and this was successfully achieved. The results from the campaign in the Jubilee field showed that a rigless approach to stimulate deepwater wells is a feasible concept. Also, it was demonstrated that the technology is mature enough for its implementation on deepwater assets offshore Ghana. However, specific conditions like geographical location, weather conditions, water depth, equipment availability, etc, will have to be carefully considered before its implementation in other locations.

Productivity of the well was successfully restored. Total oil rate from the treated wells increased from circa 10,000 bopd prior to treatment, to more than 35,000 bopd after the rigless acid stimulation.

The value creation from the treatments is not only in the uplift in well or field oil rates, due to restoration of the initial well productivity, but also in the ability and flexibility provided to manage the drawdowns on the wells to enhance long term field performance and recovery.

Nomenclature

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>AHC</td>
<td>Active Heave Compensated</td>
</tr>
<tr>
<td>ALARP</td>
<td>As Low as Reasonable Possible</td>
</tr>
<tr>
<td>CT</td>
<td>Coiled Tubing</td>
</tr>
<tr>
<td>DP</td>
<td>Dynamic positioning</td>
</tr>
<tr>
<td>EQD</td>
<td>Emergency Quick Disconnect</td>
</tr>
<tr>
<td>FPSO</td>
<td>Flotation, production, storage and offload vessel</td>
</tr>
<tr>
<td>GPRS</td>
<td>Global Positioning Reference System</td>
</tr>
<tr>
<td>HCl</td>
<td>Hydrochloric Acid</td>
</tr>
<tr>
<td>HIPAP</td>
<td>High Precision Acoustic positioned system</td>
</tr>
<tr>
<td>ICI</td>
<td>Intervention Choke Insert</td>
</tr>
<tr>
<td>ID</td>
<td>Internal Diameter</td>
</tr>
<tr>
<td>IWOCS</td>
<td>Intervention and Work over control system</td>
</tr>
<tr>
<td>LBL</td>
<td>Long Base Line</td>
</tr>
<tr>
<td>MODU</td>
<td>Mobile Offshore Drilling Unit</td>
</tr>
<tr>
<td>MPSV</td>
<td>Multi Purpose Supply vessel</td>
</tr>
<tr>
<td>NM</td>
<td>Nautical Miles</td>
</tr>
<tr>
<td>NPT</td>
<td>Non Productive Time</td>
</tr>
<tr>
<td>NRV</td>
<td>Non Return Valve</td>
</tr>
<tr>
<td>OCA</td>
<td>Organic Clay Acid</td>
</tr>
<tr>
<td>POB</td>
<td>People on Board</td>
</tr>
<tr>
<td>ROV</td>
<td>Remotely Operated Vehicle</td>
</tr>
<tr>
<td>THSIP</td>
<td>Tubing Head Shut in Pressure</td>
</tr>
<tr>
<td>WST</td>
<td>Well Stimulation Tool</td>
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<tr>
<td>WSS</td>
<td>Well Stimulation System</td>
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