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Real Time Matrix Stimulation Engineering - A Novel Approach for Optimized Treatments in Deepwater Brazil

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Abstract - For over 20 years, in the main fields in Deepwater Brazil, matrix stimulation treatments have been carried out in sandstone reservoirs, where several sand control techniques and chemical treatments have been widely implemented. In recent years, an operator faced challenges found in carbonate reservoirs, such as high permeability profile contrast, heterogeneous porosity distribution, and long producing intervals, which demand selective matrix stimulation treatments.In the past, matrix stimulation treatments were pumped using the "bullheading" technique at high pump rates with chemical diverter agents. However, the approach was ineffective, for these multiple zone reservoirs showed nonuniformely stimulated intervals on post-treatment evaluation logs due to high variations in the permeability profile. Nowadays, stimulation treatments can benefit from the use of coiled tubing (CT) with real-time monitoring of downhole parameters during intervention. Key parameters, such as pressure, temperature, and depth are tracked. The gathered information is compared to petrophysical data and available post-treatment production log results, allowing the Matrix Stimulation Engineering (MSE) team to evaluate and adjust the chemical pumping schedules accordingly. Selective fluid placement techniques along the target producing zones are then employed, which have resulted in overall improvement of the well productivity.

The current article describes how a multidisciplinary MSE team optimized in real-time the acidizing treatments in carbonate formations in Deepwater Brazil. This approach has led to impressive oil production rate results as the matrix stimulation treatment is based on a deep understanding of reservoir and well productivity by selecting and implementing appropriate fluid placement techniques.

Index Terms—Matrix Acidizing, Coiled tubing, Real-time Stimulation, Production enhancement, New technique, Innovative approach, Introduction, Implementation, Improve Efficiency, Oil & Gas Recovery Rate, Well Intervention, Raphael Mohallem.

1 Introduction

Although the new discoveries in carbonate reservoirs in the deepwater Brazilian market represent a huge undertaking, on acidizing terms, many of the challenges faced nowadays are very similar to those found in old carbonate reservoir fields. Problems, like high permeability contrast, heterogeneous porosity distribution and long production intervals have their complexity increased by the completion and production needs. Despite all these problems, the use of conventional approaches, applying basic techniques, has produced good results leaving some opportunities to development of more specific solutions, to overcome the remaining limitations.

Conventional fluid placement techniques used in offshore Brazil in matrix stimulations.

During the last 20 years, the main oilfields in Brazil were represented by sandstone reservoirs, producing an intense development in sand control techniques and chemical treatments for those rocks, while carbonates, and their correspondent chemical treatments, were considered as secondary objectives

1. For the unpacked zones, the coiled tubing is run in holewith jetting nozzles to the perforated interval into thelowest permeable zone, and around 20 - 50 bbls of HCL15 % are pumped with the intent of creating a fluid losszone. Also, operator uses wash-pipes to spot some acidand gain injectivity. Thereafter, a viscosified acid ispumped as a single big stage.

2. For packed zones, well completion with Sliding Sleeves(SS), one at the top and another one at the bottom. Theacid is spotted into the most permeable zone.

Engineering analysis was done identifying the behavior of the fluid placement from the tubing to the annular and the interaction with the formation, considering fluid flow behavior according to the downhole conditions. It has been demonstrated that in high permeability contrast the improvement of the fluid placement was negligible. Also pumping rate variations have been evaluated and taken into account for the fluid distribution.

A pilot field in Espiritu Santo Basin was selected to deploy all the efforts needed without dismissing any other matrix stimulation treatment. Flow units of the reservoir are associated to C, M-1, M-2 and M-3 formations. The first flow unit "C" features the best petrophysical properties and very high productivity. The big concern in this flow unit is associated with high saturation zones at formation base. The operator is very careful of not over-stimulating this zone that has the risk to produce water at early exploitation stages. Some areas of "M" formations have tight carbonate units with less than 8 mD. The operator usually perforates intervals of more than 50 m with 6 shots/ft or 12 shots/ft distributed evenly to cover the flow units. A multidisciplinary team from Well Intervention, Matrix Stimulation, and Reservoir Engineering departments, was established to cover areas of reservoir understanding, technology to be applied, dynamic fluid placement, real time operation monitoring and evaluation, resulting in an application of those conventional techniques associated with chemical diversion have been intensively used although mechanical diversion has also been deployed for an optimized well stimulation solution. Several challenges were addressed by performing a reservoir understanding and productivity analysis based on petrophysical evaluation. Several assumptions were used to run synthetic production logs with certain formation damageand residual skin after matrix stimulation treatments. Fluid placement was a challenge that was overcome with a combination of mechanical isolation and chemical diversion. Based on all the results for all those scenarios, stimulation treatments evolved from a simple high-rate "bullheading" to an engineering designed chemical treatment in three main stages, using mechanical and viscosified or self diverting acids to improve the homogeneity of fluid injection. In conjunction, the coiled tubing equipped with fiber optic was used to monitor at all times the bottomhole pressure and temperature and evaluate the effectiveness of the chemical treatment. It also was used to monitor the parameters of the inflatable packer (mechanical diverter), always keeping it within its operational limits. This allows both operator and service company engineers to take "in-situ" key decisions in terms of fluid volume optimization, pumping rates and stages sequence.

2.Equipment Description

Modular Offshore Coiled Tubing Unit: it was designed as a flexible, fit-for-purpose system to improve safety, service delivery and footprint for offshore operations. System comprises five main skids:

1. a hydraulic power pack

2. a control cabin

3. a drop in drum reel

4. two transport baskets that contain well control equipmentand injector

Historically, the performance and reliability of the CT operations had been associated with the capability to interpret in an assertive manner thebottomhole parameters, such as pressure and temperature, as well as to ensure a precise CT depth control. In a response to the industry's demand for the ability to make informed decisions about downhole parameters, Coiled Tubing with fiber optics was developed to provide real-time bottomhole measurements, which features the following main components:

1. The fiber-optic carrier (FOC), which is required fortelemetry communication between surface acquisitionand bottomhole sensors. The FOC usually contains fouroptic fibers. Two are used for communication to thesensors, one is for backup, and the fourth fiber is usedfor Distributed Temperature Surveying (DTS)measurements. The FOC is non intrusive (Fig.

2)allowing conventional operations to be carried out, suchas pumping corrosive fluids and usage of bottomholeassemblies such as inflatable packers or high pressurerotating nozzles. The entire optical fiber by itself is usedfor the acquisition of DTS. By monitoring thetemperature changes over time at a regular intervalalong the fiber (every 0.5 meter), it is possible to identify,in real time, features representative of specific eventsdownhole, such as injection points or chemical reactions.

Coiled Tubing Equipped with Optical Fibers

2. The bottomhole assembly consists of the CT head withoptical fiber connections, electronic communicationsystem, battery, and sensors to measure: temperature,
pressure (internal and annulus), and casing collarlocator (CCL) for depth correlation.

3. The surface acquisition system consists of an electronic package mounted onto the CT reel. The acquisition system converts the optical signal into a wireless digital signal, thus enabling communication with the computer located in the CT control cabin. This computer is equipped with specialized software, which displays the job parameters data in real time.

This technology allows operators to measure bottomhole parameters in real-time, thus reducing uncertainty through the course of CT operations, and eventually paving the way for more informed decisions. Such as, the case of the CT deployed Through-Tubing Inflatable Packer.

CT Deployed Through-Tubing Inflatable Packers are composed of the following two main components:

1. The CTD-TTIP system is specifically designed to perform reliable through-tubing zonal isolation. This system includes a hydraulic inflatable packer set, as well as the option to connect it to real-time pressure and temperature sensors. The system is designed to perform single-trip, single-set zonal isolations. The packer is capable of expansion ratios of 3:1 at a differential pressure up to 2,000 psi.

2. The tension- and pressure- operated running tools have tension mechanisms designed to release the bottomhole assembly and/or to deflate the CTD-TTIP. It is important to remark that these tension devices are not affected by the differential pressure, making them safe during the high inflation/injection pressures exerted within the CTD-TTIP. The pressure-operated tools arededicated to inflating the packer with a safe mechanism to avoid over passing the limits of the element.

Several calculations must be made to determine if a CT deployed Inflatable Packer is suitable or not for a specific application. Specific engineering calculations are made using dedicated software and known well conditions to both
optimize the design and reduce risk. The calculations include three stages:

1. The 1st stage is before inflating the CT deployed Inflatable Packer.

2. The 2nd stage is just after the inflation of the CT deployed Inflatable Packer. At this point, both ΔP1 and ΔP2 are equal. The pressure difference is defined as the difference between the packer´s pressure and the pressure above and/or below of it. The value for both cases at the packer’s maximum pressure is the inflationpressure plus a safety margin.

3. The 3rd stage is the injection through the CT deployed Inflatable Packer and, depending on the application, it could be above, below, or dual injection. At this time it is extremely important to avoid exceeding the pressure limits otherwise the intervention might be compromised. Those limits are dictated by the tubular’s inner diameter at the anchoring depth.

Thanks to the real-time downhole measurements provided by the CT with Fiber Optic, these three conditions are monitored at all times during the selective matrix stimulation treatment in an effort to detect and address any malfunction of the CT deployed Inflatable Packer.High-Pressure Jetting system deployed with CT. This system has several advantages compared to conventional nonrotating nozzles, likewise:

1. Positive one-pass cleaning with 360° wellbore coverage

2. Nozzle head-controlled rotation for maximum jetting thrust

3. Engineered for harsh environments

4. Non-metal cutting or gridding action, resulting in nondamage to completion installations.

Viscosified and Self Diverting Acids. The VSDA has the following characteristics:

1. Polymer-free fluid

2. It has a rapid viscosity development

3. Easy to break when in contact with hydrocarbons or external breakers

4. It can be used as stimulation fluid and diverting agent at the same time

The VSDA is used as the main stimulation fluid for carbonate formations due to the advantages that is brings when acting as a chemical diverter.

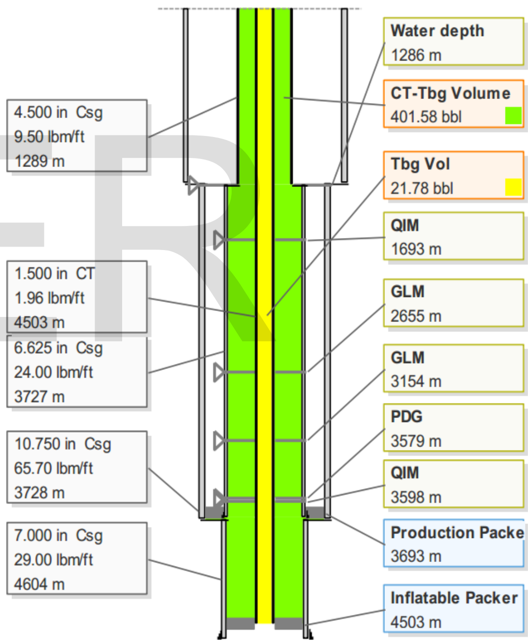
3.PRESENTATION OF DATA AND RESULTS

Case Study 1: Well B–2.

The exploratory well B-2 is located in the Espirito Santo Basin. The water depth is beyond 1,300 m. As shown in Fig. 5, it was completed with a 6-5/8-in tubing and a 7-in producing casing. It was perforated in two intervals: the upper interval is located at 4,310 – 4,458 m and the lower one at4,550 – 4,580 m. The permeability profile is highly contrasted between zones; the lower zone features an average permeability of 100 mD, while the upper interval presents an average permeability of 10 mD.

Due to high vertical permeability contrast between the lower and the upper zones, and taking into account the fact that the lower zone was only 28 m from the water-oil contact, it was requested by Reservoir Engineering to perform a low strength acid treatment in the lower zone and a more aggressive chemical batch on the upper, less permeable zone.

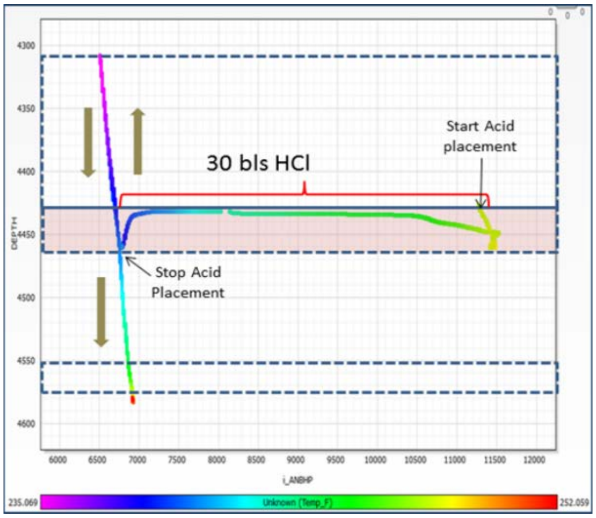
There was confidence that the rates and distances between zones would be enough to divert the acid system to the lower permeable zone. It was proposed to use the CT with fiber optics and real-time downhole measurements (pressure and temperature) to evaluate the stimulation treatment and to be able to take informed decisions in case the treatment schedule needs to be modified by incorporating diverter fluids between acid stages.



Well Schematic B-2

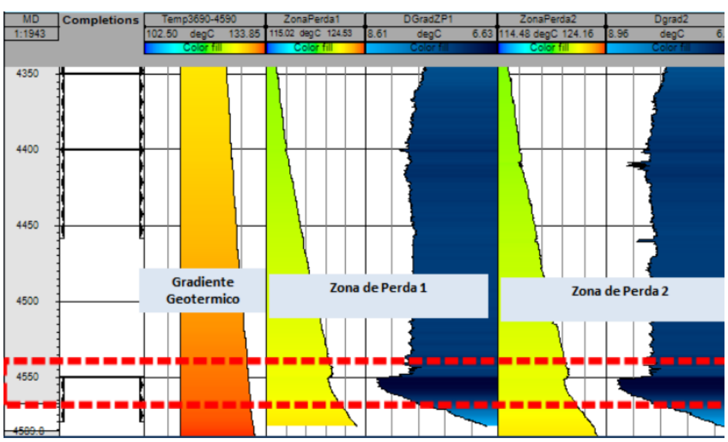
The matrix stimulation design consisted in pump 30 bblsof HCl pumped through the CT with fiber optics and using a high pressure jetting system to create the thief zone. Moving the CT in the interval (4,458 m – 4,431 m) and then bullheading a treatment of 1,700 bbls (150 gal/ft) of VSDA mainly composed by HCl, a particular attention was paid to not over-stimulate the lower zone that had the risk to produce water at early exploitation stages.

The injectivity test was unsuccessful at a pressure up to 11,500 psi. The reason of the non-injectivity was possible due to the use of loss control fluids at drilling or completionstages. It was also noticed a sharply pressure drop just afterthe acid was spotted on the interest zone to a BHP of 6,750 psi.



Pressure drop after acid placement

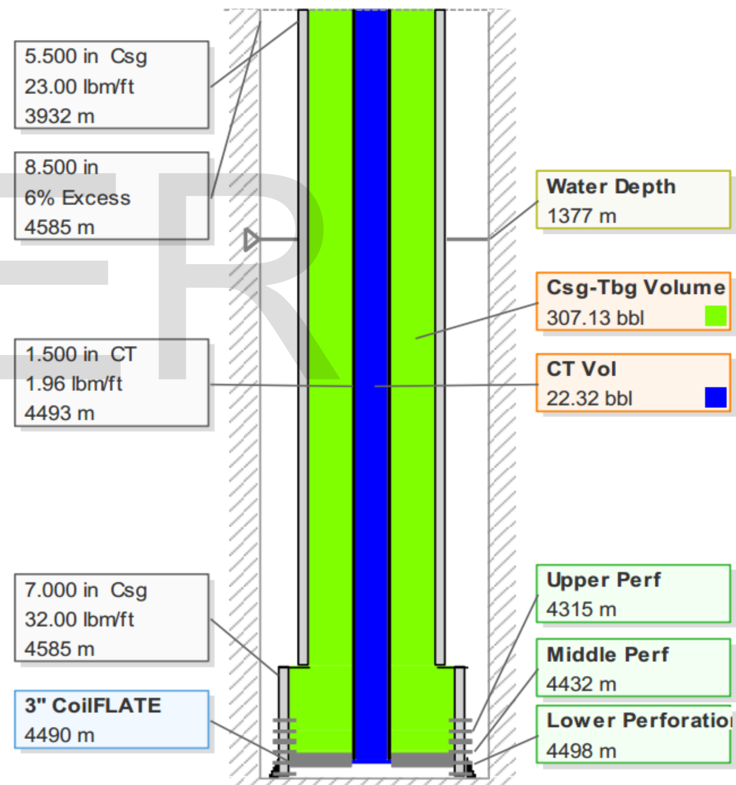
The bullheading treatment was pumped as per design and it was noticed that due to the high permeability contrast the improvement of the fluid placement was negligible. Also, pumping rate variations had been evaluated and taken into account for the fluid distribution. During this stage it was identified that more than 90% of the fluid flow went into the top of lower interval (4,550 – 4,560 m), the most permeable zone.



Comparison of Temperature Profiles (Geothermal Gradient vs. Fluid Pumping Stages)

Case Study 2: Well B–6

The exploratory well B–6 is also located in the EspiritoSanto Basin. At a water depth beyond 1,377 m, it was completed as shown in Fig. 8 with a 5-1/2-in tubing and a 7- in producing casing. It was perforated in three intervals: the upper interval at 4,315 – 4,400 m, the middle interval at 4,432 – 4,482 m, and the lower interval at 4,498 – 4,558 m. The permeability profile is highly contrasted between the 3 zones: the lower zone features an average permeability in the range of 120 mD, while upper and middle intervals exhibit an average permeability of 8 mD.Originally, the matrix stimulation treatment for the well B- 6 was planned similar to the one on the well B-2 (i.e., by a CT placement at the bottom and bullheading for the aggressive chemical volume in the upper zone). During the job execution, it was clearly noticed that due to the high permeability contrast, most of the acid went to the top 3.5 m of the lower zone, the most permeable one. This was corroborated by the Production logging results.



Based on the results of the intervention at well B-2 (case study 1), a change was operated in the strategy of the Stimulation Engineering Department. The new strategy involved the use of mechanical diverters such as CT deployed Inflatable Packer to isolate the different zones and perform selective matrix stimulation treatments. To be able to set a CT deployed Inflatable Packer several challenges were taken into consideration based on the previous experience at well B-2, such as:

- Reservoir Pressure of 6,750 psi @ 4,580 m

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• Initial condition: zero injectivity

• After acid wash with HP Jetting System, connectivitycould be accomplished between the well and the reservoir

• An abrupt pressure fall was noticed after HCl placement, from 11,500 psi down to 6,750 psi

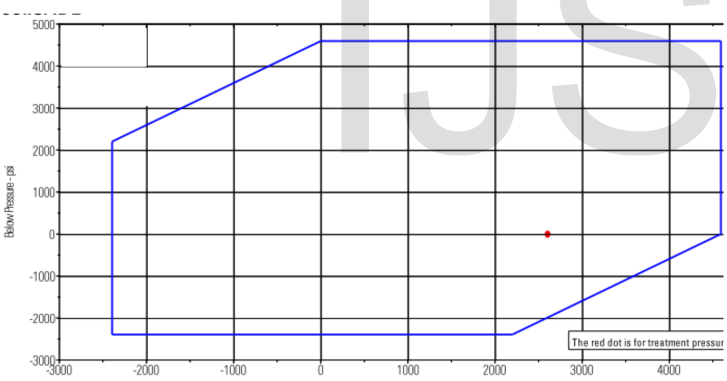
• Delta pressure increase after the acid wash, up to a maximum of 1,500 psi

•Bottomhole temperature of 129°C

• Temperature fall down range between 55°C to 50°C

In order to use the CT deployed Inflatable Packer, it is needed to determine the maximum injection pressure before fracturing the formation and exceeding the limits of the CT deployed inflatable packer. The Fig. 9 shows the limits of the CTD-TTIP working pressure envelope. The red dot is the simulation of the maximum injection pressure during the job and the blue line is the maximum element burst's pressure.

The red brace is showing the emergency valve opening pressure range (2,990 to 4,000 psi).



CT deployed Inflatable Packer working envelope

For the well B-6, the following proposal was considered and evaluated:

1. Tubing Conveyance Perforating (TCP) of all the reservoir producing zones, well completion and rig up of the Subsea Christmas Tree

2. CT acid placement on the lower and most permeable zone, with 20 bbls of HCl plus 140 bbls of VSDA, reciprocating the pipe between 4,498 to 4,558 m.

3. Zonal isolation by placing a CTD-TTIP between the lower and middle zones

4. Stimulation by bullheading of the upper and middle perforated zones a total of 1,500 bbls of VSDA

5. CTD-TTIP retrieval by applying 8,000 lbf of over-tension

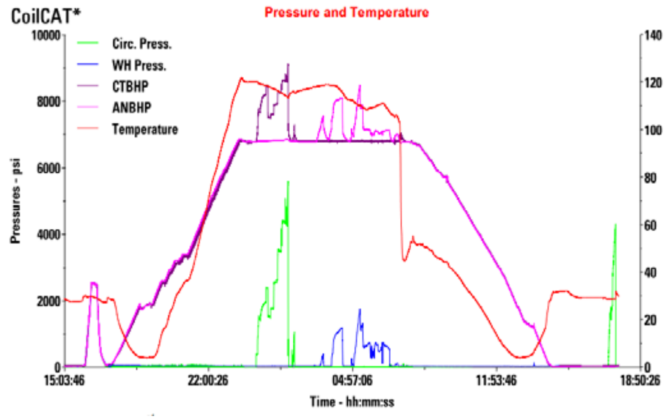
6. Zonal isolation by placing a CTD-TTIP between upper and middle zones

7. Stimulation by bullheading of the upper perforated zone using 9 batches of 110 bbls of acid and 100 bbls of VSDA

8. CTD-TTIP retrieval by applying 8,000 lbf of over-tension

This selective matrix stimulation treatment proved to be technically and economically adapted to the field's needs and was thus selected. It is important to note that the CCL sensor from the CT with fiber optics was used as a correlation method for the inflatable packer deployment. This step was critical due to the setting window for the inflatable packer was 16 m. After performing step 2, the CT with fiber optics was retrieved to surface and the inflatable packer was deployed and run in hole. After reaching the target depth, the inflatable packer was inflated and tested the effective anchor, thus isolating the lower zone. An injectivity test was successfully achieved. Then, 1,500 bbls of VSDA were pumped by bullheading in the annulus space between CT with fiber optics and production tubing to stimulate the middle and upper zones. Once the treatment was finished, the inflatable packer was deflated and retrieved to surface.

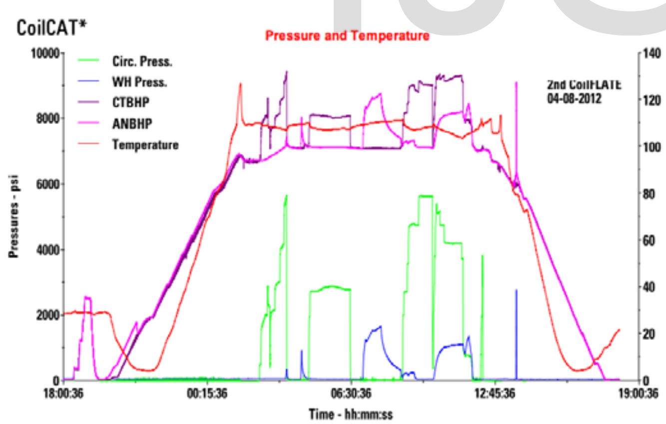
During the stimulation treatment, the downhole parameters were monitored to evaluate the effectiveness of the acid treatment. The CTD-TTIP was inflated as per design, reaching an inflation pressure of 2,200 psi. During the bullheading treatment between the CT-Tbg, it was noticed that downhole pressure was below the fracturing pressure. Once the treatment finished, the CTD-TTIP was deflated. Then, it was noticed a drastically temperature decrease indicating the effective isolation between zones.



*Mark of Schlumberger

1st CT deployed inflatable packer downhole readings

After the 1st selective matrix intervention, the inflatable packer was changed and a 2nd inflatable packer was run in hole and set between the middle and upper interval. Injectivity test was carried out with negative results. 20 bbls of HCl acid were pumped through the CT and above of the inflatable packer to soak the upper interval. A new injectivity test was unsuccessfully done. It was decided to cancel the 2nd bullheading treatment. The CT fiber optics and the CT deployed inflatable packer were retrieved to surface.



2nd CT deployed inflatable packer downhole readings

The results from production logging showed that production was originating mainly from the middle interval and, to a moderate extent, from the lower interval. After the well was reassumed to well testing, the production results were 25% more than expected oil rate, thus making it the top 13th highest oil producer well in Brazil (Jan 2013) and 27th in terms of gas production.

Case Study 3: Well B-4.

Like the other two wells, the exploratory well B-4 is also located in the Espirito Santo Basin, at a water depth of 1,328 m. As shown in Fig. 12, the completion consists in a 6-5/8-in tubing and a 7- in producing casing. It features four perforated intervals: the upper interval at 4,308–4,338 m, the middle top interval at 4,451–4,481 m, the middle lower interval at 4,487.5 – 4,499 m, and finally the lower interval at 4,506–4,550 m. The permeability profile is highly contrasted between zones, the lower and middle lower zones featuring an average permeability in the range of 120 mD to 1 D, and the upper and middle top intervals presenting an average permeability of 8 to 10 mD.

Based on the results of the intervention at well B-6, the following proposal was considered and evaluated for well B-4:

1. Tubing Conveyance Perforating (TCP) of all thereservoir producing zones, wellcompletion and rig up ofthe Subsea Christmas Tree

2. CT acid placement on the lower and most permeablezone, with 140 bbls of HCl, 10 bbls of high strenghtHCl,and 80 bbls of V-SDA, while reciprocating the pipe between 4,506 to 4,550 m. Position the CT at 4,570 m tocover all intervals and bullhead 1,350 bbls of V-SDA inthe annular space between CT and production tubing,while monitoring with DTS the injection profile.

3. 1st zonal isolation by placing a CT deployed inflatablepacker at 4,503 m between the lower and middle lowerzones in a window of 7 m, correlating using the CCLsensor.

4. Stimulation by bullheading of the upper, middle top and middle lower perforated intervals with a total of 600 bblsof V-SDA while monitoring the downhole pressure andtemperature to determine the injection points

5. CT deployed inflatable packer retrieval by applying 8,000lbf of over-tension

6. 2nd zonal isolation by placing a CT deployed inflatablepacker at 4,484 m between the middle lower and middletop zones in a window of 6.5 m correlating using the CCLsensor.

7. Stimulation by bullheading of the upper and middle topperforated intervals with a total of 500 bbls of V-SDA (ifthe injectivity test is positive) while monitoring

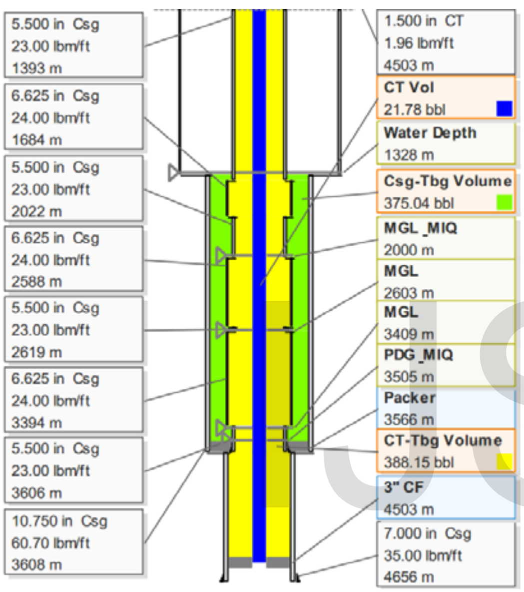
thedownhole pressure and temperature to determine theinjection points

8. CT deployed inflatable packer retrieval by applying 8,000lbf of over-tension

9. 3rd zonal isolation by placing a CT deployed inflatablepacker at 4,400 m between the upper and middle topzones.

10. Stimulation by bullheading of the upper perforated zone by pumping 300 bbls of V-SDA (if the injectivity test is positive)

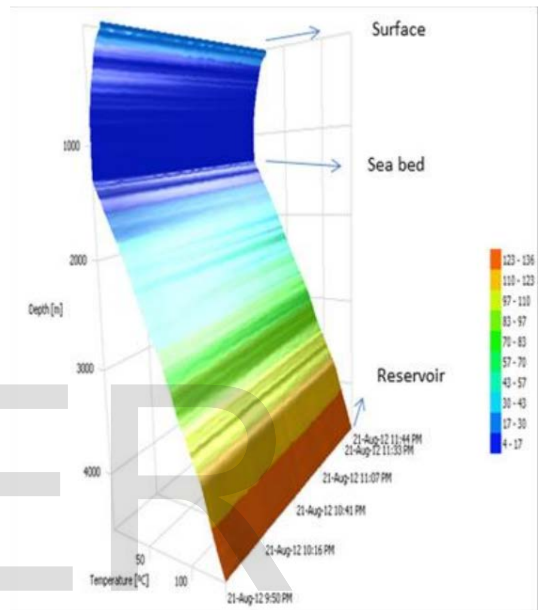
11. CT deployed inflatable packer retrieval by applying 8,000 lbf of over tension



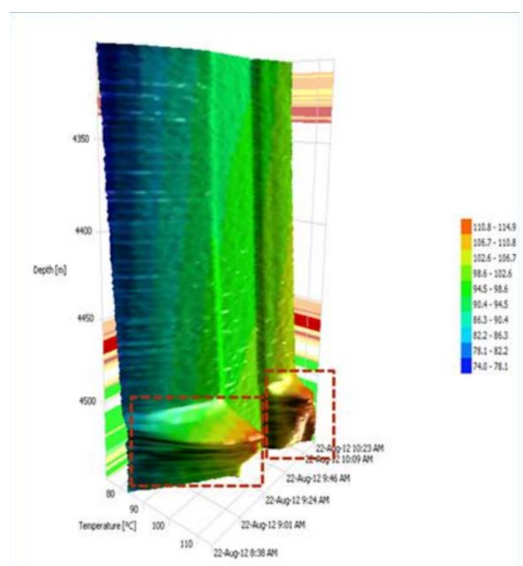
Well Schematic B-4

This selective matrix stimulation treatment was deemed feasible both technically and economically and was thus selected. It is important to note that the CCL sensor from the CT with fiber optics was used as a correlation method for the inflatable packer deployment. This step was critical since the setting windows for the CTD-TTIP were only 7 m and 6.5 m. The main difference from the intervention at well B-6 was the introduction of the DTS to evaluate in a qualitative way the injection profile along the intervals while being stimulated. A key to analyze temperature profiling in oil and gas wells is to understand how the wellbore fluid gains or losses heat as it interacts with the formation and the wellbore, as well as how the Joule Thompson effect3 impacts its temperature variations. When taking those different effects into consideration, the changes in temperature over time are used to determine the fluid flow repartition along the completion and, more specifically, at level of perforations. The 1st step before pumping any treatment was thus to acquire the temperature baseline profile, or geothermal baseline1 .

The 2nd step was executed as planned, pumping the chemicals through the CT along the perforations. Then, the CT with fiber optics was positioned at 4,570 m before bullheading a treatment made of 1,350 bbls of acid. During the acid injection, temperature changes only occurred in front of the lower and most permeable interval , confirming once again that the zones with better petrophysical properties will govern the fluids injection.



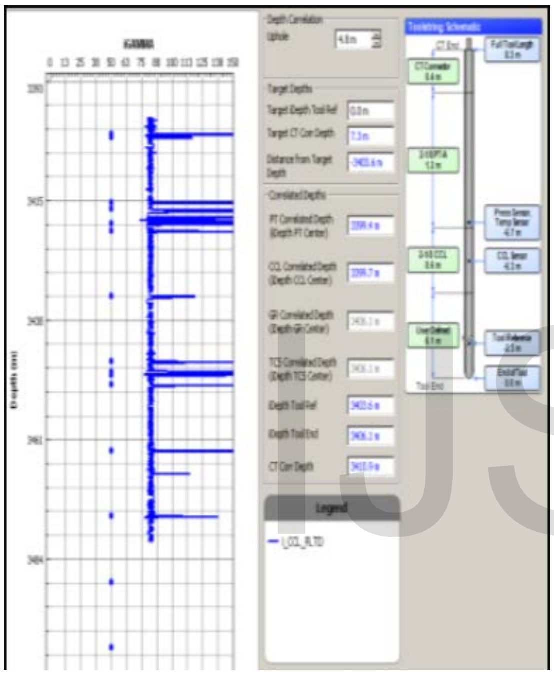
Baseline on well B-4



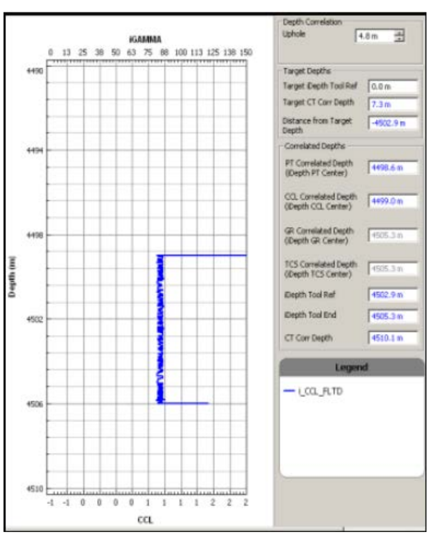
DTS during the bullheading

Due to high pump rates during bullheading, the temperature in the tubulars coolded down from 130°C to 40°C. Practically, the fluids arrived until the base of the C formation. Small temperature changes were observed during the "bullheading" pumping due to the high fluid velocity outside of the CT with fiber optics.

After performing step 2, the CT with fiber optics was retrieved to surface and the inflatable packer was deployed and run in hole. After reaching target depth, the CCL sensor was used to identify the jewelry on the completion and the identification of the top of the lower zone at 4,506 m and the bottom of the middle lower zone at 4,499 m

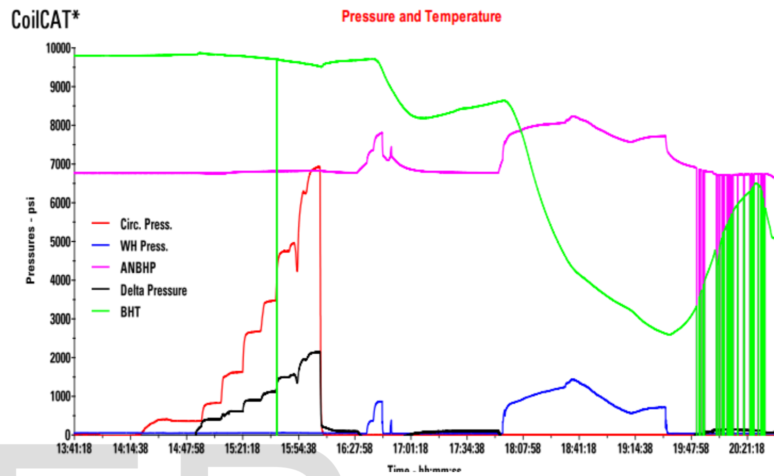


CCL on Completion



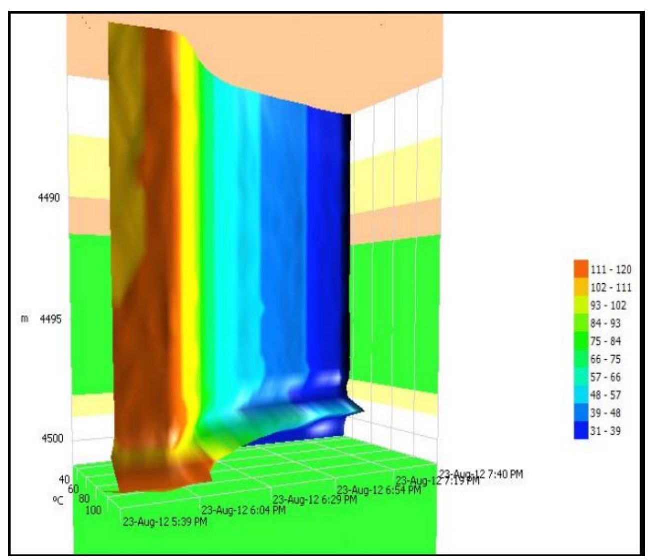
CCL between middle lower and lower zones

The CTD-TTIP was inflated and tested the effective anchor, thus isolating the lower zone. An injectivity test was successfully done achieving a maximum bottomhole pressure of 8,000 psi. Then, 600 bbls of VSDA were pumped by bullheading in the annulus space between CT and Tubing to stimulate the middle lower, middle top and upper zones. Once the treatment was finished the inflatable packer was deflated and retrieved to surface .



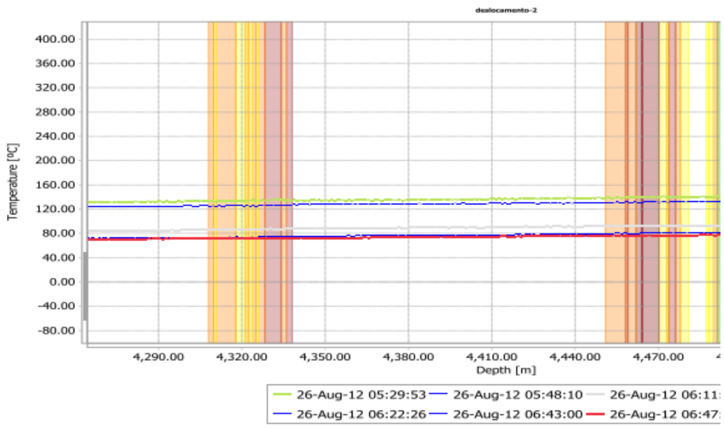
CT deployed inflatable packer setting and bullheading treatment

During bullheading, the temperature profile shows a higher cooldown at the base of the middle lower interval (4,487.5m to 4,499.0 m).



DTS profiling during the bullheading treatment

The 2nd CT deployed inflatable packer was then set at a depth of 4,483 m. A new injectivity test was performed, with a negative result. Due to the noticed low injectivity, the rest of the treatment was cancelled, meaning that the middle top and upper zones were not stimulated since they are very tight formations. At the end of the treatment, the wellbore fluids were over displaced into the formation by diesel. On the DTS profiling, one can observe that the pumped fluid travelled down to a depth of 4,540 m. In addition, most of the fluid went into the interval located between 4,425 m to 4,540 m.



DTS profiling during final displacement

After the well was reassumed to well testing, the production results were outstanding, with an oil production rate 100% higher than expected, therefore making it the top oil well in Brazil (Jan 2013) and 11th in terms of gas production.2

4. Conclusions

A multidisciplinary team from Well Intervention, Matrix Stimulation, and Reservoir Engineering departments was established to deliver a unique integrated solution by covering areas of reservoir understanding, applied technologies, dynamic fluid placement, real time operation monitoring and evaluation, resulting in an application of conventional techniques associated with chemical and mechanical diversion for an optimized well stimulation solution. Several challenges were attained taking decisions "in-situ" by following this engineering approach:

- Dynamic Reservoir understanding
- Flow unit contrast validation
- Well productivity optimization
- Enhanced Fluid placement accordingly to each stage of treatment
- Skin evolution during time
- Pumping schedule optimization
- Matrix stimulation evaluation
- Accurate depth control throughout the entire intervention
- Optimized downhole tools operation through knowledge of downhole parameters.

The most remarkable results of the novel MSE approach, are that the well B-4 (2nd place) and well B-6 (13th place) are in the top-15 oil producers wells, and as well as, for gas producers they are ranked as follow: the well B-4 (11th) and B- 6 (27th) both of them in the top-30 gas producers in June 2013, although the interventions were executed over a year ago.3 As a result, the operator is requesting the integration of those technologies in their common matrix stimulation engineering process.

5. Acknowledgment

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