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A Novel Approach to Salvaging Well Completions with Mud Damage using a Specialized Fluid System; The First Cases in Nigeria

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Abstract

Well re-entry necessary to wash/cleanup suspected barites and barium sulfate residues in two wells located onshore Niger Delta, Wells AA & BB drilled and completed to develop a cumulative of over 700 Bscf of gas and 30MMstb of associated condensate reserves at an initial cumulative potential of 240 MMscf/d, producing below par at about 15% planned daily production.

The sand face for these Single String Gas Producers were drilled with 13.8ppg POBM. Post well completion, hookup and initial cleanup, the wells were suspected to have remained suspended with drilling and completion debris also, various HUD's were encountered within completion string.

Previous reentries proved rather unsuccessful for the operator as these wells could not be cleaned up even after using 3 different traditional stimulation fluids pumped in high volumes. As a result of the challenges experienced during the previous interventions, the operator sought a different approach which included the deployment of a specialized stimulation treatment, which is a mixture of organic acids, solvents and clay inhibitors with built in corrosion sequestration and de-emulsifiers via CT.

This specialized two-fluid treatment comprising of pre-flush and main treatment was sequentially pumped and allowed to soak for 5hrs and 36hrs respectively.

CT run planned to be performed with a jetting tool run across the SAS was not feasible as there was no access to the bottom of the SAS assembly as several attempts to mill out the HUD encountered in the tubing string proved abortive.

This paper aims at presenting advances in barite dissolving capability with non-damaging stimulation fluid and powerful "descaler" which although reacts quicker in warm environments (>100°F), is not largely temperature dependent to reach depletion with normal reactions taking place within 24hours. The post stimulation results and recovered debris validates the dissolving capabilities for cleaning sulphates of barium, strontium and calcium as well as calcite in wellbores.

Introduction

Well AA and Well BB located in Nigeria's Niger Delta region, are a part of a cluster of wells in that region, developed by one of the biggest operators in the Nigerian oil and gas industry, to significantly increase the production of LNG by 70% which will strengthen the domestic market and maintain supply to the export market.

These two wells are from an onshore block located in the central Niger Delta Region of Nigeria. Fig 1 below shows a map of the location of the region. This block contains a major integrated oil and gas project which is important because it harnesses significant volumes of associated gas that had previously been flared, while also commercializing several non-associated gas reserves. This project also involves the re-development of several oil reservoirs that produced prior to the integrated project design. This project is developing production from an area of approximately 650 square kilometers. These fields were discovered in the 1970s but not fully developed because they contained mainly gas, for which there was little demand then in Nigeria. The project is currently drilling more than 30 new wells and has installed a central processing facility on site to treat both oil and gas.

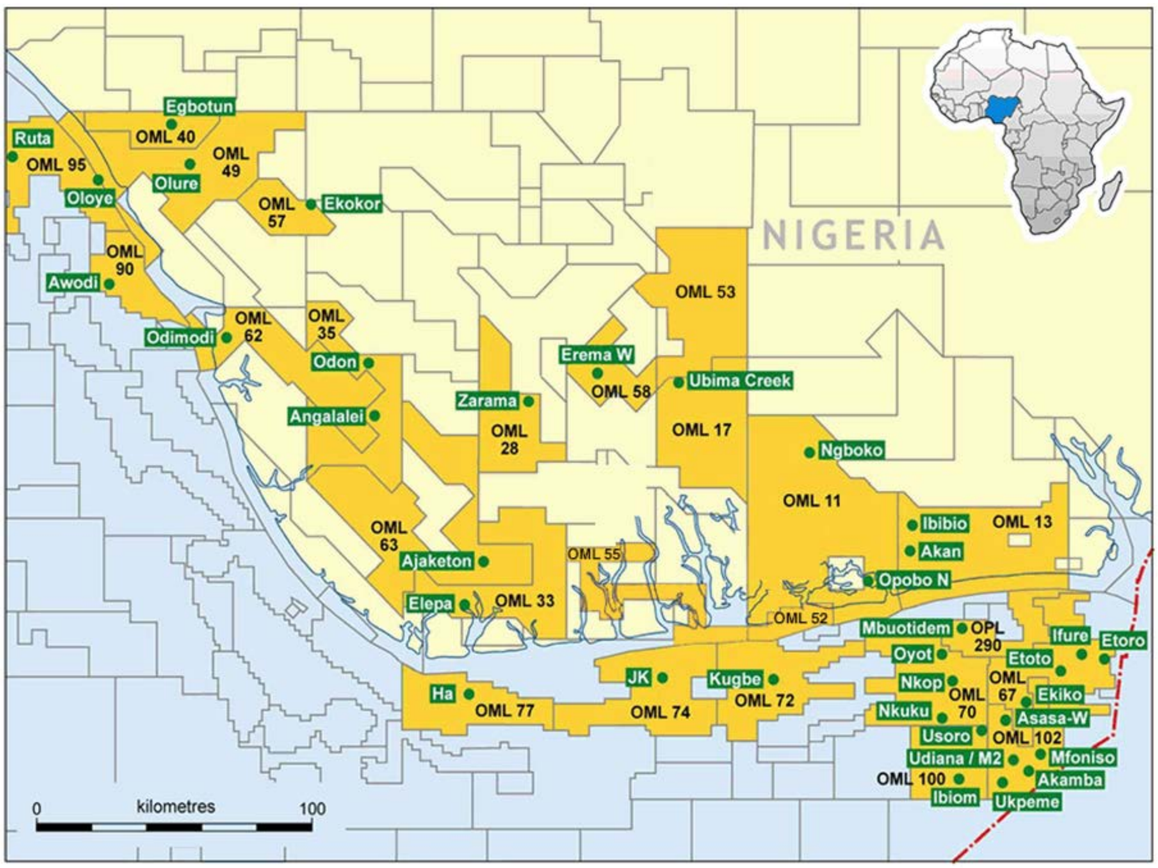
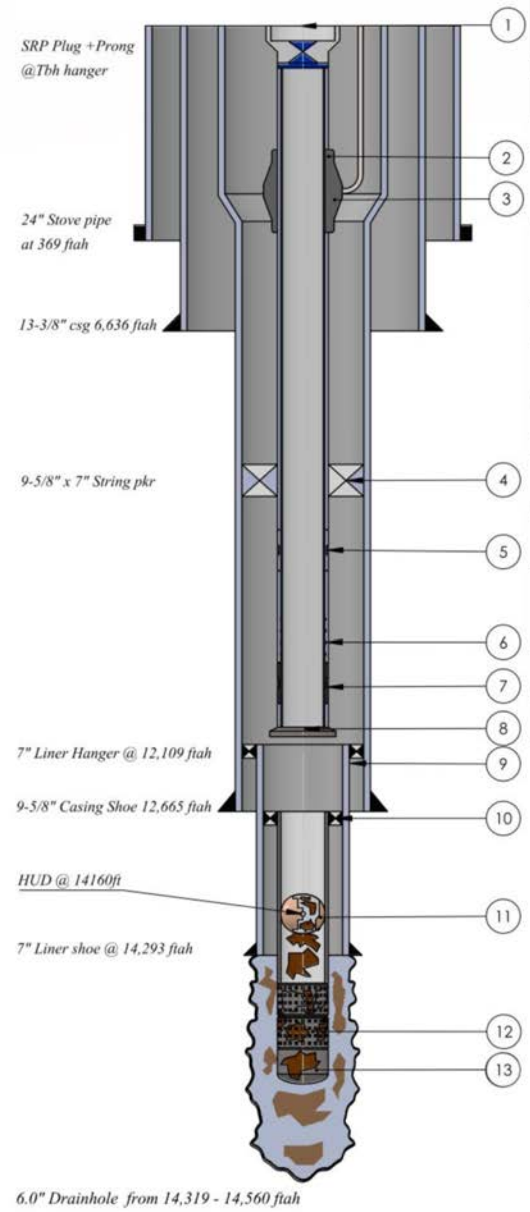


Figure 1—Location Map of Niger Delta, Nigeria.

These wells are a part of the 2nd phase of this key integrated oil and gas project for which a breakdown of the peak production is approximately about 800 million standard cubic feet of gas per day (MMscf/d) and 20,000 barrels of condensate per day. This will increase production from the area, help meet government targets to reduce flaring, provide more energy for Nigerians and increase exports of liquefied natural gas.

These two wells drilled and completed between 2014 – 2017 are almost similar single string gas producers with depths of about 14000ftah, recording reservoir pressures of above 9000psia and temperatures of above 200°F. Post drilling, the expected total recovery from these wells are 180 Bscf of gas / 10 MMstb of associated condensate reserves and 500 Bscf / 20 MMstb of gas and associated condensate reserves respectively at an initial potential of 120 MMscf/d per well.

Fig 2. below details the completion schematic of one of these wells showing the 13Cr completion equipment used for this well due to its nature, which includes 7" tubing equipped with tubing retrievable surface - controlled subsurface safety valve (TRSCSSV), 7" 32ppf liner, open hole standalone screen assembly installed across the sand face complete with a formation isolation valve installed to enable the displacement of fluid prior to installing the upper completions.



LEGEND				
S/N	DESCRIPTION	Depth (ft)	Max. O.D (in)	Min. I.D (in)
1	Elevation	0.00		
2	7" Flow coupling 32# 13Cr FN, H563 B x P	169.5	7.676	5.984
3	7" TRSCSSV 7" 32# H563 13 Cr w/c 'RPT' Profile	175.15	7.99	4.56
4	TNT Packer, 9-5/8", 53.5#, 7" 32#, H563 Box x Pin S13Cr, Perm Pkr/Mill to retrieve	11,926.78	8.31	6.00
5	RPT Nipple 5.5" 13Cr 95MY, 20# S13Cr Vamtop HC b-P Box x Pin, 4.5" Profile	11,986.56	6.122	4.5
6	Perforated Tubing Joint, 7" 32ppf H563 B x P	11,995.17	7.660	6.094
7	RN Nipple 4.313" 5-1/2" - 23, Fox - KBox x Pin, 13Cr	12,037.56	6.189	4.100
8	7" 32# 13Cr H563 Box Wireline re-entry guide	12,087.33	8.300	6.460
9	Liner Hanger 9-5/8" x7"	12,109.00	8.400	6.130
10	7" 13Cr 32-35# VCA Packer 5 13/32-8 Stub acme	14,099.56	5.820	3.880
11	7" x4-1/2" FIV Assy (mechanical mode), 4 1/2" 12.6# Vamtop HC B X P	14,162.02	5.520	2.940
12	4-1/2" 13Cr 12.6ppf Vam Top Box x Pin SAS 225 microns (screen + accesories) X4	14,310.67	5.060	3.958
13	4-1/2" 13Cr 12.6ppf Vam Top Box Bull Nose	14,474.66	6.00	
NOTE: ALL DEPTHS ARE TOP DEPTHS ALONG HOLE BDF, COMPLETION MATERIALS ARE 13Cr				

Figure 2—Status of Well AA before Intervention

The sand face for these wells lie in typical sandstone reservoir and were drilled with 13.8 ppg POBM, weighted with barite to create adequate hydrostatic pressure which in turn ensured primary well control against downhole pressures that had been recorded to be >9000psi.

Post drilling and completion, the wells were re-entered twice in 2017 using CT and the standard clean up fluids for well clean-up activities, offloading & Multi Rate Testing. Clean up activities on these wells, carried out as scheduled with indications of almost zero BS&W, stabilized tubing head pressures and flowing tubing head temperatures but recorded various hold up depths (HUDs) which prevented the CT string from getting to the bullnose. After the cleanup & MRT, Flowing Tubing head pressures for both wells were far less than what was expected. Lead Impression Block (LIB) run indicated that presence of barite cake in the wellbore believed to be as a result of the drilling mud used during drilling operations

Well AA came on stream in July 2017 with an average daily production rate of 20MMscf/d of gas at a FTHP of about 4000 psig. The well was closed in from November to December 2017 for clean-up and testing. Thereafter the well was re-opened and production maintained at ca.15MMscf/d.

Well BB came on-stream in January 2018 and was put on production at an average daily production rate of 30 MMscf/d of gas at about 6500 psia against a planned production rate of 120MMscf/d. Cumulative production from both wells was ca. 45MMscf/d as against the planned ca.240MMscf/d

The inflow of both wells was suspected to be impaired by barite settling inside the well bore and some plugging the screen. Intervention was planned for these wells using coil tubing and a clean-up solvent to soak the well and flow back thereafter.

The challenge however lay with the identification of a clean-up solvent that can effectively clean the well bore & the plugged screen as the clean-up / stimulation fluids used previously were unable to dissolve the barite.

Statement of Theory and Definitions

Barite is a common source of formation damage especially when used in cases such as with the wells described in this paper. Barite based drilling fluids by necessity carry large volume of fine solids into the wellbore and in conjunction with drilling fluid filtrates or completion fluids form mineral complexes which often lead to pore throat closure, tubular restriction and often partial / full production loss. The cause of Barite deposition or settling in any well bore is usually a result of a suspension of a well in drilling fluid or subsequent settling, or the completion brine being contaminated with the drilling fluid resulting in the drill fluids solids settling out.

Wells drilled and subsequently completed with gravel packs and screens, often experience clean up problems or complete blockage. This blockage can be said to be as a result of the filter cake forming a layer on the screen mesh rather flowing through the screens. This type of blockage can be as a result of poor drilling fluid selection or maintenance during the drilling phase.

Impairment caused by barite is usually very difficult to remove once it has occurred as barite is not soluble in the usual inorganic oilfield acid that are used for stimulation operations.

Barite cake can be removed from the wellbore mechanically by using a jetting tool, brushing or even drilling through the cake and chemically by soaking the impaired area with an effective "barite dissolver".

For the wells under review, it was almost impossible to only mechanically clean out the damage due to the holdup depths recorded during previous reentries therefore chemically removing the damage was the only viable option.

Studies have shown that chemically removing impairment caused from barite can be done using aminopolycarboxylic acids (chelating agents) EDTA and DTPA with a converter or a catalyst because a major challenge is the slow rate of dissolution of barite.

Description and Application of Equipment and Processes

While the operator of these wells was burdened with effectively selecting the required equipment for this work scope it was also important to ensure that recommending the proper chemical treatment alongside this equipment was done to ensure that the impairment on these highly economically viable wells was cleaned out totally.

Generally, designing the chemical treatment and method of deployment to be used depends on the down hole conditions existing at the time. In order to be closely accurate in the design of the recovery fluid treatment essential information was requested for and provided. Tests were run with the information provided and a treatment design was made for the operator. This process is detailed in Fig. 3 below.

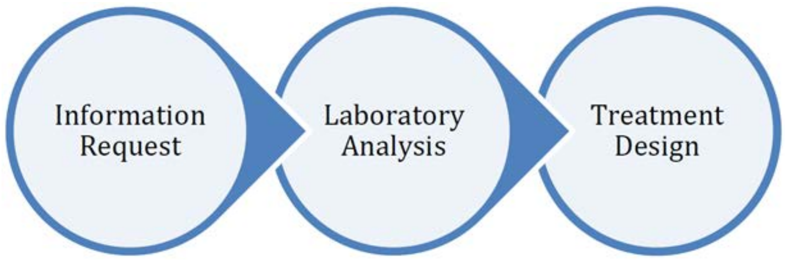


Figure 3—Treatment Design Process Flow Chart

Information Request

The following information was requested from the client as follows:

a. Well Schematic detailing completion design and perforation location
b. Well drilling, drilling fluid and completion fluid history
c. Original completion operation details – problems
d. Production and testing history
e. Stimulation history
f. Production zone lithology and chemical analysis
g. Production/injection fluid analysis
h. Current well state (suspended, producing, shut in etc.)
i. Contaminant/blocking agent analysis (scale, barite plugging, cement etc.)

Laboratory Testing / Analysis

Understanding that the production impairment was caused by POBM, for which barite was a part of indicates that the cake to be removed will possibly be oil wet. To proffer an in-depth solution, considerations had to be made for the removal of oil coatings/ films around the solid contents / completion equipment and ensure that they are left water wet and can be treated accordingly. The operator was unable to provide samples from the well, but since LIB run indicated the presence of barite cake, Laboratory testing was carried out with barite cake samples built in the laboratory bearing similar properties of what was believed to be in the well and the following test methods shown in Table 1 were used to identify the treatment variants to be deployed for this case. Fig 4 and Fig 5 also show laboratory test samples using this specialized treatment fluid system.

Table 1—Summary of Laboratory Testing

Grams/Liter Dissolved= $\left(\frac{1000mL}{x\,mL}\right) * \mathit{Start\ Weight} - \mathit{Ending\ Weight}$			
S/n	**Description**	**Testing**	**Results @ 140°F Grams / Liter dissolved**
1	Solvent #1 + Fresh Water + Barite Cake	Weighed samples were added as per procedure, hot rolled for 18hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried.	73.8
2	Solvent #2 + Barite Cake	Weighed samples were added as per procedure, hot rolled for 4hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried.	89.0
	Solvent #1 + Freshwater + Barite Cake recovered from above	Components added to cell, hot rolled for 18hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried.	
3	Solvent #2 + Barite Cake	Weighed samples were added as per procedure, hot rolled for 4hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried for 4 hrs.	146.2
	Solvent #1 + Freshwater + Barite Cake recovered from above	Components added to cell, hot rolled for 4hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried.	
	Solvent #1 + Freshwater + Barite Cake recovered from above	Components added to cell, hot rolled for 4hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried.	
4	Solvent #1 + Freshwater + Barite Cake recovered from above	Weighed samples were added as per procedure, hot rolled for 4hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried.	132.8
	Solvent #1 + Freshwater + Barite Cake recovered from above	Components added to cell, hot rolled for 4hrs at 140°F, Sample collected on filter paper, washed with distilled water and dried.	

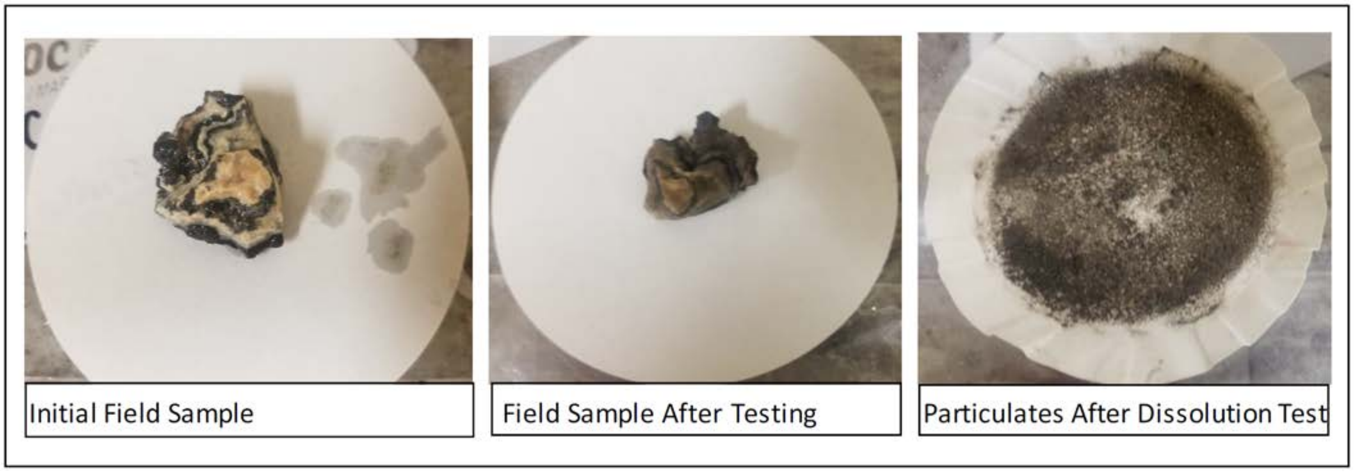


Figure 4—Laboratory Dissolution Testing

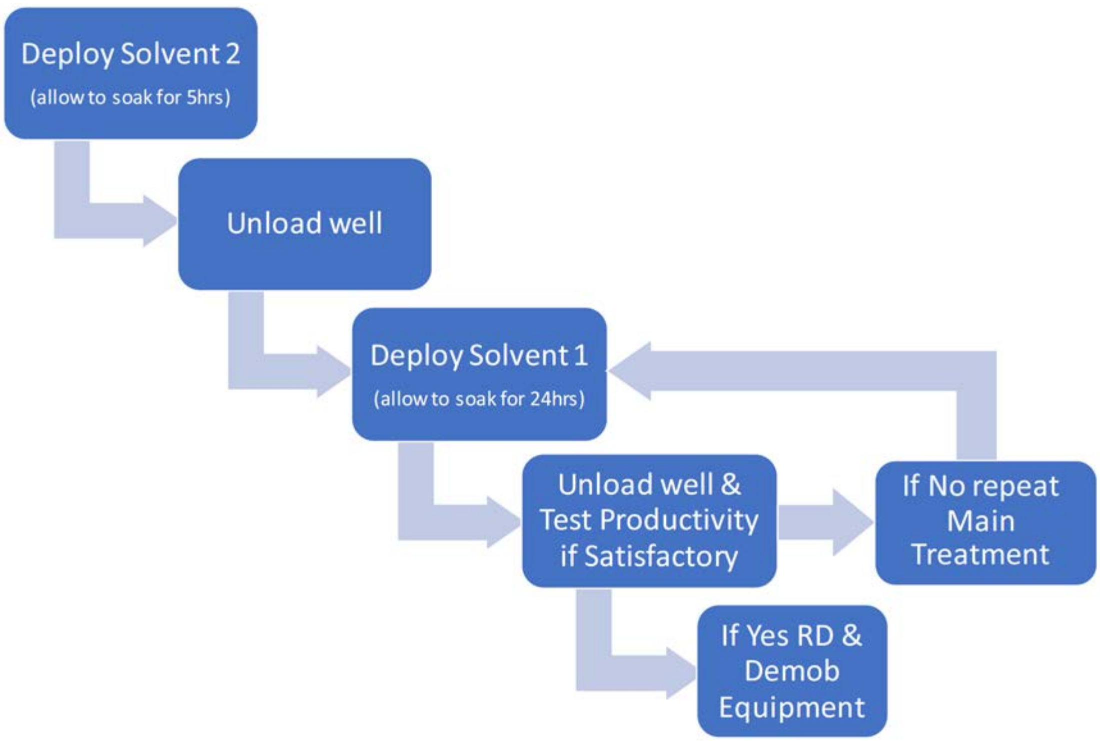


Figure 5—Treatment Design

Treatment Design

From the result of the laboratory analysis detailed above, it can be seen the dissolution of barite increased by 20% using a 2-stage treatment of a preflush before the main treatment as against the 1 stage treatment of only the main treatment. Further testing showed that repeating the main treatment on the same sample increased the rate of dissolution by 100% and reduced treatment time to 8hrs.

As had been identified, the source of the barite is from oil based drilling mud and as such the barite cake to be treated will be oil wet, hence the requirement to use a second solvent first to remove oil films and water wet as much of the solids to enhance the rate of dissolution prior to the introduction the main solvent for dissolution.

Operational Summary

Equipment selection for live intervention on these gas wells included a 1.75" OD Coiled Tubing, 130,000psi yield strength, internally tapered string with a 125k unit. The CT stack, surface lines, xmas trees valves, flare lines, upstream / downstream valves of the choke manifold were all tested to 500psi (low) for 5 minutes and 10000psi (high) for 15minutes with no indications of surface leaks.

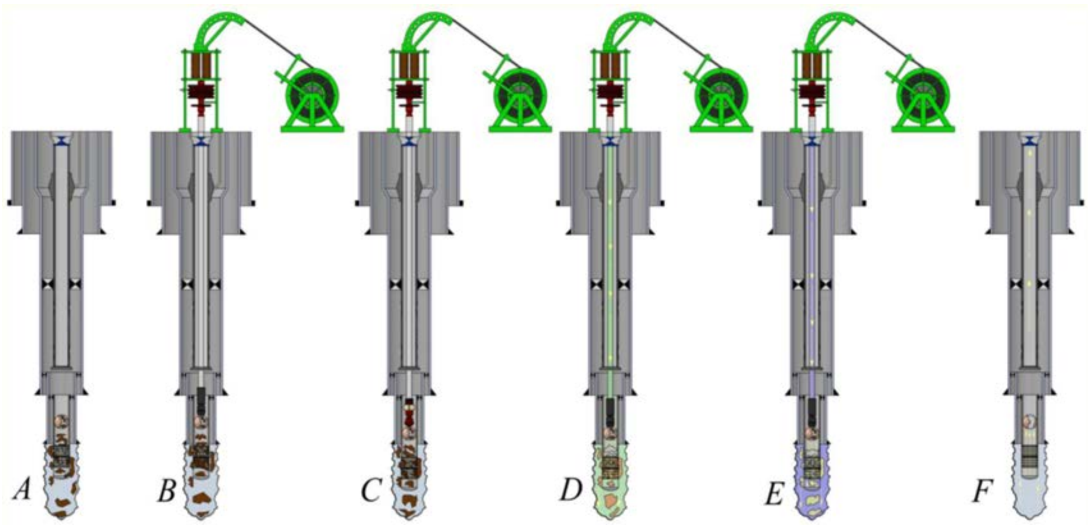
CT ran in hole with a jetting nozzle with the plan of making passes and jetting the treatment across the screens and tag the screen bullnose. However, the presence of the HUD at about 14100ft for the first well necessitated the contingency milling run which was unsuccessful. A third run had to be made with the jetting nozzle which terminated above the HUD and a positive injectivity test was carried out which indicated that the treatment could be squeezed into the severely damaged area from above the HUD. The treatment for well AA and BB were carried out in stages as have been detailed below. The only difference in the two operations apart from the treatment volumes pumped is that for Well BB, due to lessons learnt from Well AA, the first and only CT run was done with the milling assembly, thereby eliminating a run with the cleanout BHA, to tag the HUD and attempt to remove same. This attempt to mill was also futile and as such a risk assessment was carried out on the possibility of squeezing the treatment with the milling BHA thereby also eliminating the need for another run and saving operational time gained from the elimination of two CT runs as was done on Well AA.

Post milling effort and risk assessment, positive injection from above the HUD was achieved, subsequently the treatment was done in stages through the CT to soak through the HUD and access the screens both inside and outside, allowing direct spotting of the dissolving chemicals, without having to bullhead a lot of fluid back into the formation. Different soak periods were required during the placement of the two chemicals as a single stage bullhead would be unlikely to achieve a uniform placement of the fluid over the severely scaled area.

Intervention Summary for Well – AA

Fig. 7 below summarizes the Well Intervention Operation in Well AA as follows:

Figure 6—Laboratory Precut Screen Testing



A	Original condition of well prior to intervention suspended with drilling and completion debris
B	Coil Tubing RIH with cleanout BHA to tag screen bullnose and jet treatment across screens, unable to pass HUD above screens, POOH
C	RBIH with Milling BHA attempted to mill, but unsuccessful gained only 5ft with intermittent gel sweep
D	POOH Milling BHA, RBIH with clean out BHA above HUD, with annulus shut in, squeeze 9bbl of Solvent #2 (Preflush Treatment), PU CT to safe depth and allow to soak for 5hrs
E	Open well, unload spent Solvent #2, shut in well, RBIH from safe depth to target depth squeeze 15bbl of Solvent #1 (Main treatment) and allow to soak for 36hrs
F	Unload well gradually at different choke sizes while monitoring FTHP.

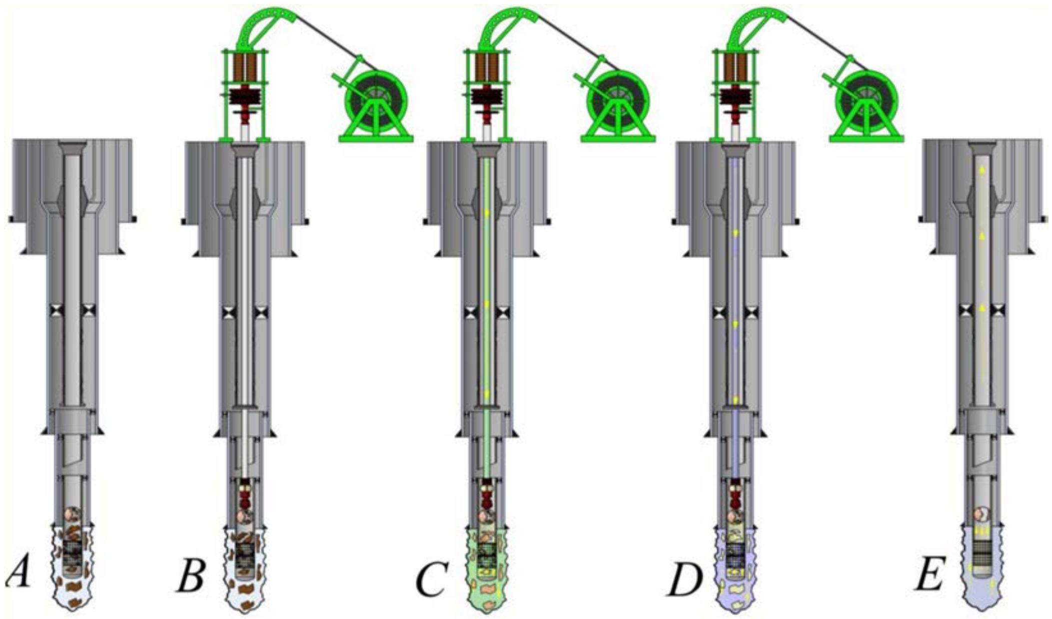
Figure 7—Schematic of Well Intervention Operations on Well AA

Table 2—Fluid Treatment Schedule & Parameters for Well AA

Solvent #2 - Pre-Flush Treatment					
	Qty	pH	Density	SG	Treatment Area
Treatment Fluid (Buffered)	9 bbl.	3.58 @ 23.6°C	9.7ppg	1.16	249ft
Solvent 1 – Main Treatment					
	Qty	pH	Density	SG	Treatment Area
Treatment Fluid (mixed)	15 bbl.	13.31 @ 23.6°C	9.55ppg	1.15	415 ft

Intervention Summary for Well – BB

Fig. 8 below summarizes the Well Intervention Operation in Well BB as follows:



A	Original condition of well prior to intervention suspended with drilling and completion debris
B	Coil Tubing RIH with milling assembly to tag Hold Up Depth at FIV with annulus closed, unsuccessful milling attempts @ HUD,
C	With annulus closed, squeezed 12bbls of solvent 2 (Preflush Treatment), PU CT to safe depth and allow to soak for 5hrs.
D	Open well, unload spent Solvent #2, shut in well, RBIH from safe depth to target depth squeeze 20bbl of Solvent #1 and allow to soak for 36hrs. POOH CT
E	Unload well gradually at different choke sizes while monitoring FTHP.

Figure 8—Schematic of Well Intervention Operations on Well BB

Table 3—Fluid Treatment Schedule & Parameters for Well BB

Solvent 2 - Pre-Flush Treatment					
	Qty	**pH**	**Density**	**SG**	**Treatment Area**
Treatment Fluid (Buffered)	12 bbl.	3.16 @ 22.7°C	9.7ppg	1.17	332 ft
Solvent 1 – Main Treatment					
	Qty	**pH**	**Density**	**SG**	**Treatment Area**
Treatment Fluid (mixed)	15 bbl.	13.31 @ 28°C	9.4ppg	1.14	554 ft

Operational Timeline

Table 4—Well AA - Operational Timeline

Planned				Actual			Variance	
S/no	Activity description	50/50 Time (hrs)	50/50 Time (days)	Activity description	50/50 Time (hrs)	50/50 Time (days)	50/50 Time (hrs)	50/50 Time (days)
1	Take over well. Move CT & pumping spread to well AA	60	2.5	Take over well. Move CT & pumping spread to well BB	72	3	12	1.5
2	Carry out upfront WHD job & drift well. RU CT and Pumping spread. PT surface equipment.	48	2	Carry out upfront WHD job & drift well. RU CT and Pumping spread. PT surface equipment.	168	7	120	5
3	RIH with jet blaster Assembly, wash screen to Bull nose / HUD. POOH.	30	1.25	RIH with jet blaster Assembly, Tag HUD. POOH.	28	1.2	-2	-0.1
4	RIH with milling tool assembly, mill obstruction and wash down to bull nose. POOH.	36	3	RIH with milling tool assembly, mill obstruction, POOH.	24	1	-12	-2
5	Test well productivity.	12	0.5	RIH with jet blaster assembly to HUD. Spot and squeeze Preflush treatment and allow to soak for 5hrs then unload well	24	1	12	0.5
6	RIH with jet blaster assembly to bull nose. Wash across the sand face with barite dissolver.	24	1	Soak well with Main Treatment. POOH CT.	48	2	24	1
7	Soak well with barite dissolver Solvent. POOH CT.	24	1	Test well productivity and hand over well to project team	72	3	48	2
8	Test well productivity.	12	0.5				-12	-0.5
9	RIH with jet blaster assembly to bull nose. Pump and soak well with barite dissolver. POOH.	24	1				-24	-1
10	Test well productivity.	12	0.5				-12	-0.5
11	Carry out Screen Perforation.	30	1.25				-30	-1.25
12	Test well productivity and hand over well to project team	30	1.25				-30	-1.25
	Total	**342**	**14.25**	**Total**	**436**	**18.2**	94	3.92

Table 5—Well BB - Operational Timeline

Planned				Actual			Variance	
S/no	Activity description	50/50 Time (hrs)	50/50 Time (days)	Activity description	50/50 Time (hrs)	50/50 Time (days)	50/50 Time (hrs)	50/50 Time (days)
1	Take over well. Move CT & pumping spread to well BB	60	2.5	Take over well. Move CT & pumping spread to well AA	24	1	-36	-1.5
2	Carry out upfront WHD job & drift well. RU CT and Pumping spread. PT surface equipment.	48	2	Carry out upfront WHD job & drift well. RU CT and Pumping spread. PT surface equipment.	48	2	0	0
3	RIH with jet blaster Assembly, wash screen to Bull nose / HUD. POOH.	30	1.25	RIH with milling tool assembly & mill obstruction	24	1	-6	-0.25
4	RIH with milling tool assembly, mill obstruction and wash down to bull nose. POOH.	36	1.5	Spot and squeeze Preflush treatment with milling assembly and allow to soak for 5hrs then unload well	24	1	-12	-0.5
5	Test well productivity.	12	0.5	Soak well with Main Treatment. POOH CT.	36	1.5	24	1
6	RIH with jet blaster assembly to bull nose. Wash across the sand face with barite dissolver.	24	1	Test well productivity	18	0.75	-6	-0.25
7	Soak well with barite dissolver Solvent. POOH CT.	24	1	Rig down and hand over well to project team	60	2.5	36	1.5
8	Test well productivity.	12	0.5				-12	-0.5
9	RIH with jet blaster assembly to bull nose. Pump and soak well with barite dissolver. POOH.	24	1				-24	-1
10	Test well productivity.	12	0.5				-12	-0.5
11	Carry out Screen Perforation.	30	1.25				-30	-1.25
12	Test well productivity and hand over well to project team	30	1.25				-30	-1.25
	Total	**342**	**14.25**	**Total**	**234**	**9.8**	-108	-4.5

Treatment System

This barite dissolution system is a dynamic system that works by establishing chemical equilibrium within the confines of the target area. The chemistry of this system accelerates and continues in breaking the target molecules apart until chemical equilibrium is established. Chemical equilibrium is established when the treatment fluid is spent, or the targeted compound is dissolved completely.

This unique non-damaging stimulation fluid system as opposed to conventional acid, (that is a damaging stimulation fluid that only dissolves $CaCO_3$) dissolves barite, $CaCO_3$, some drilling fluid additives, and magnesium, strontium, calcium, strontium and barium sulfate scales, has been seen to work at a significantly faster and higher capacity than any other system. It is a single phase, alkaline (pH +/-12) chemical that is non-corrosive, environmentally benign, and produces no precipitate or gas by-products. It also is inhibitive to clays, inorganic and has no known temperature limits.

This system has been validated in well cases in the Gulf of Mexico, the North Sea; as shown in Fig. 10, and has also been validated here in Nigeria with Well AA and Well BB. With all these attributes, this system can be said to be effective, safe, and easy to use with significant advantages over traditional acid.

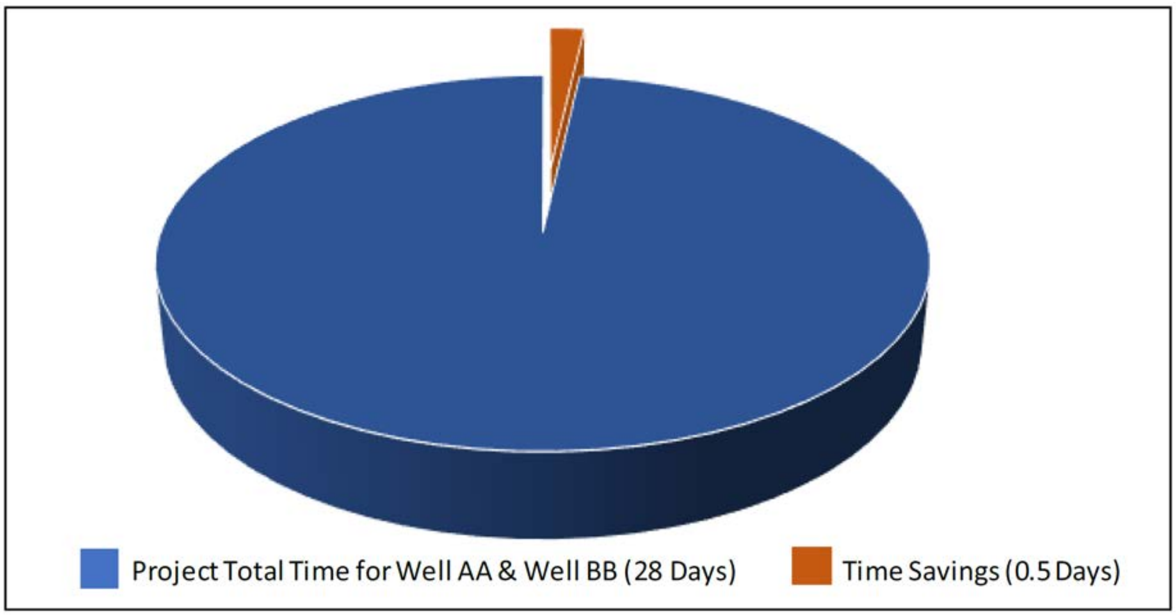


Figure 9—Total Project Operational Performance

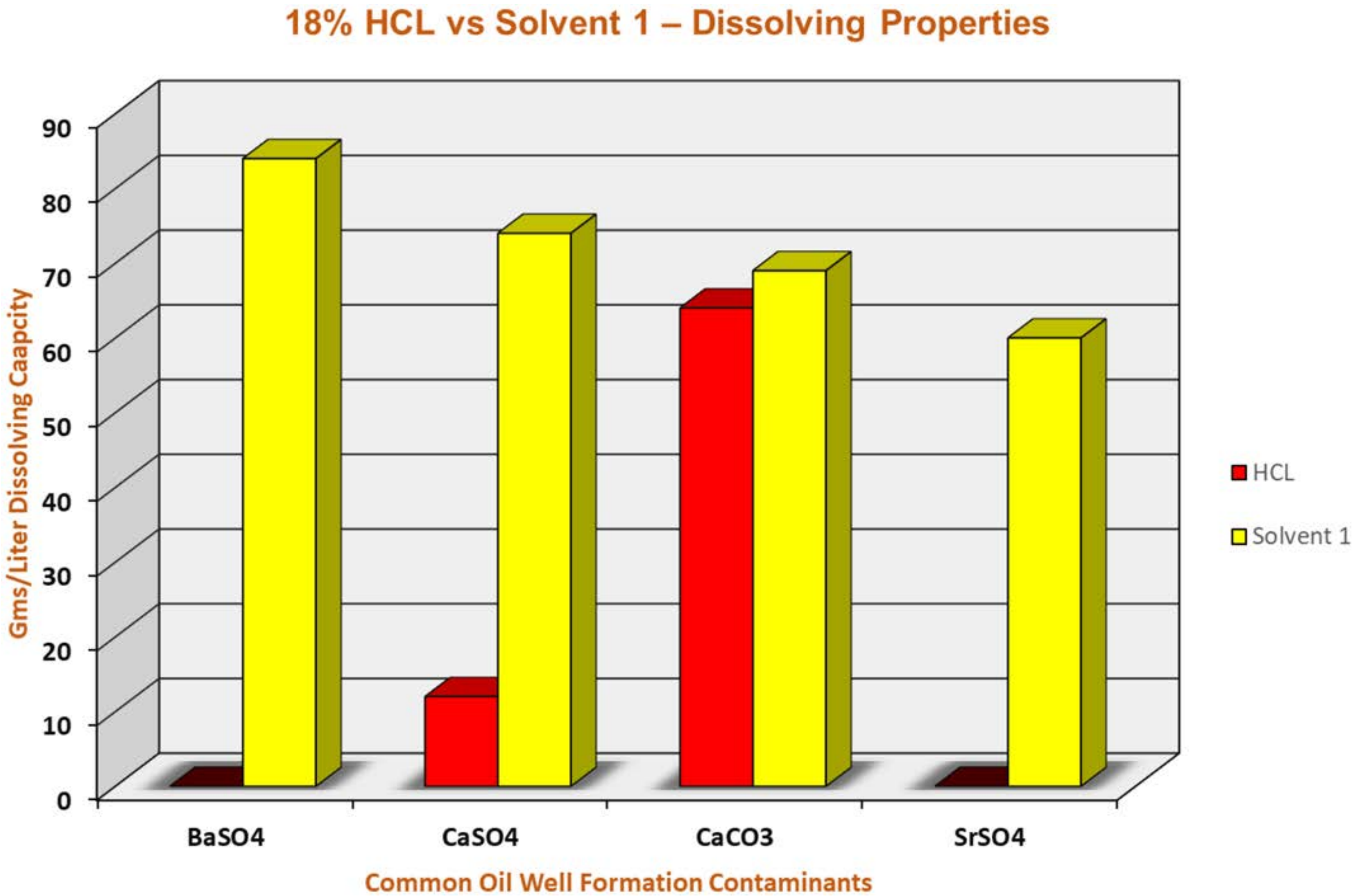
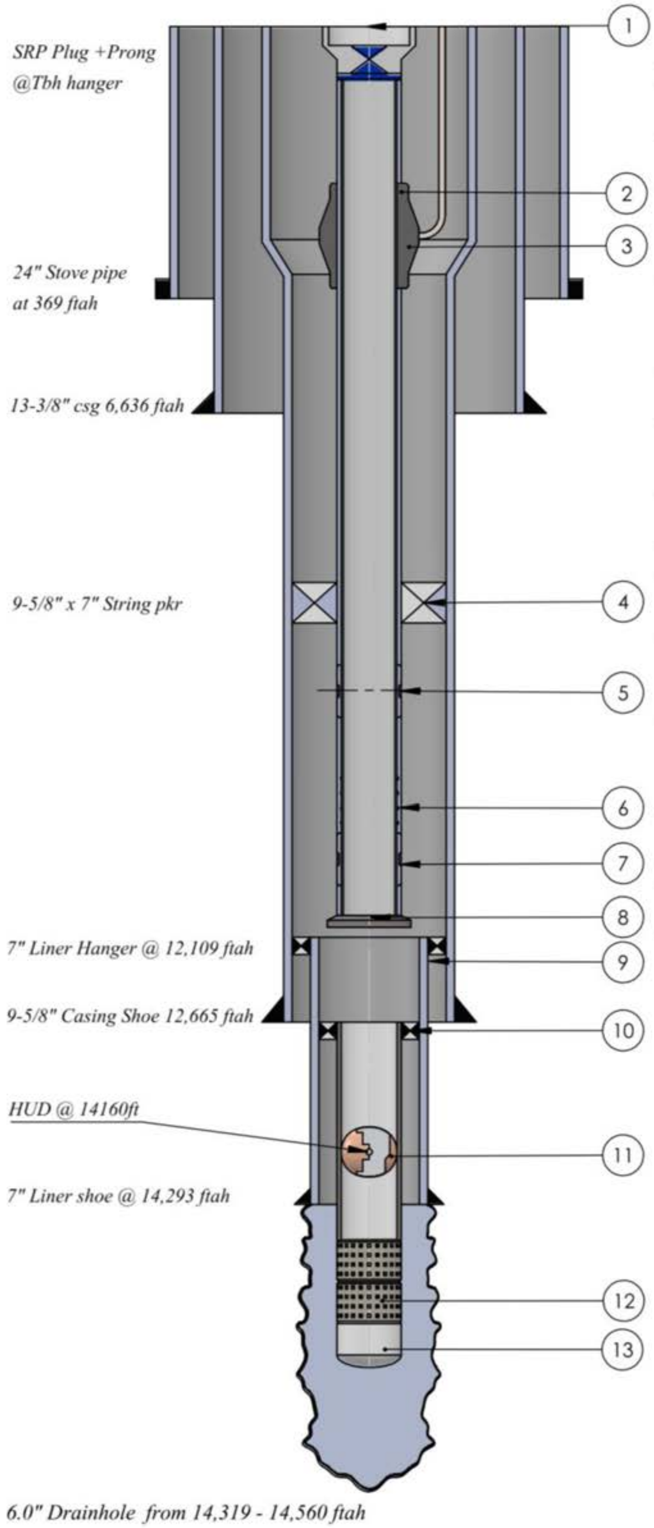


Figure 10—Chart showing dissolving capabilities of Solvent 1 vs HCL derived from testing at BP Sunbury in England

Results and Conclusion

The rigless live well intervention operation on Well AA and BB was successfully done without the need to carry out a full workover on the wells which would have required a workover rig to retrieve the entire completion string leading to huge cost savings for the operator.

After previous attempts to clean up the damage in these wells using three different stimulation fluids pumped in high volumes, the operator finally recorded success in cleaning up the wells and restoring production to the wells as they had been developed for, shown in Fig.11. Fig. 12 shows a sketch of the timeline and production summary for both wells.



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NOTE: ALL DEPTHS ARE TOP DEPTHS ALONG HOLE BDF, COMPLETION MATERIALS ARE 13Cr

Figure 11—Status of Well AA After Intervention

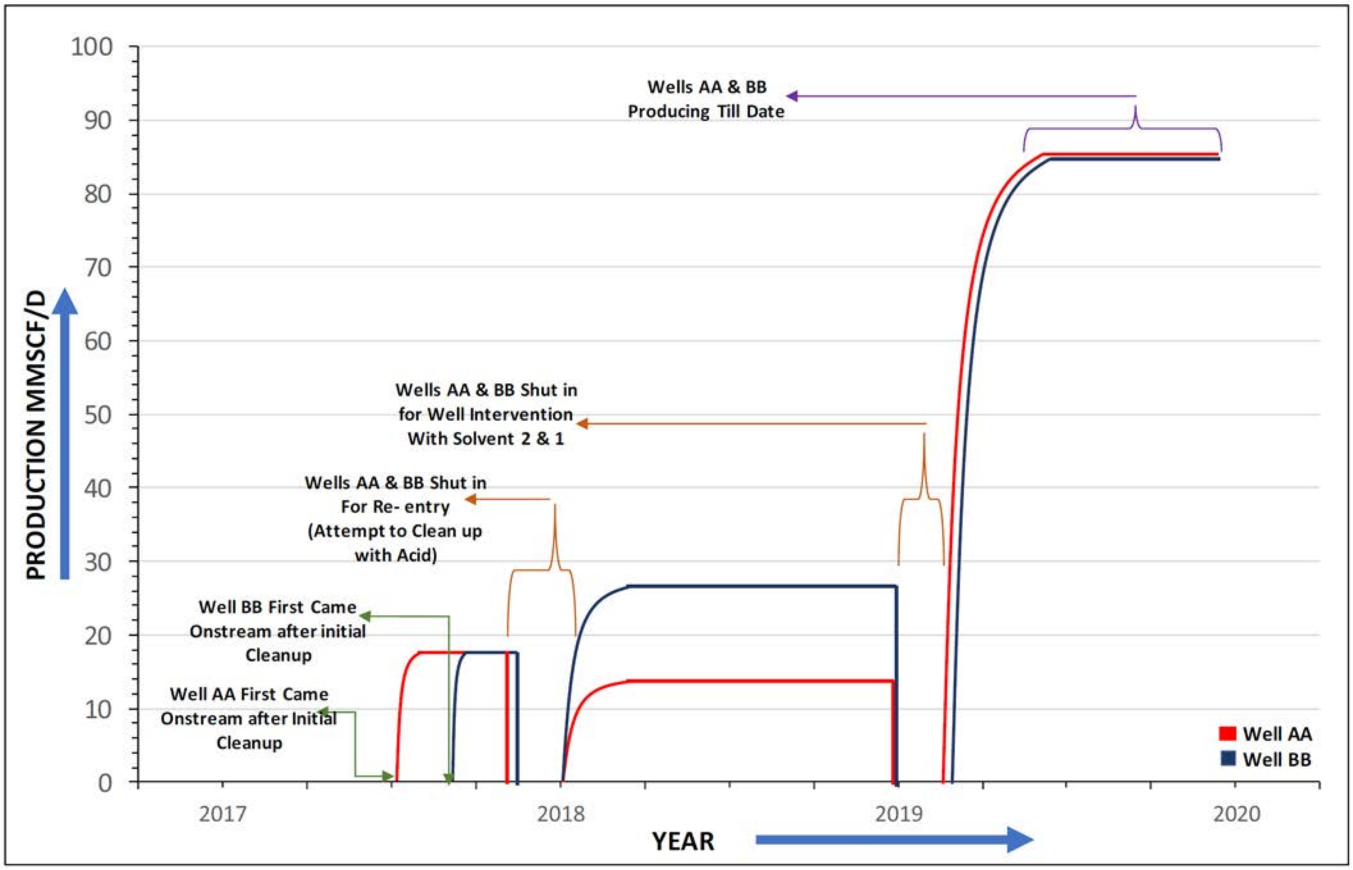

Figure 12—Production Timeline & Status of Wells AA & BB

The importance of laboratory testing cannot be over emphasized as it goes a long way in reducing uncertainties in these kinds of operations as it was the first of its kind to be recorded in Nigeria's Niger Delta region. The rig less well intervention program was successfully executed with the zone being cleaned – with large amounts of scale removed from the well and production restored. Post-job well test and production results from the operator of these wells which indicate a 375% increase in production, has proven the success of the design and procedure implemented in such challenging wellbores. The customer's expectations were exceeded, and sand screen integrity reestablished.

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Nomenclature

BBL Barrels
BHA Bottom hole Assembly
BSCF Billion Standard Cubic Feet
CT Coil Tubing
CTU Coil Tubing Unit
DPTA Diethylenetriamine Penta acetic Acid

EDTA	Ethylenediaminetetraacetic Acid
FIV	Formation Isolation Valve
FT	Feet
FTHP	Flowing Tubing Head Pressure
°F	Degree Fahrenheit
HCL	Hydrochloric Acid
HUD	Hold Up Depth
HRS	Hours
ID	Inner Diameter
LIB	Lead Impression Block
LNG	Liquified Natural Gas
MMSCF/D	Million Standard Cubic Feet per Day
MMSTB	Million Stock Tank Barrels
MRT	Multi Rate Test
OD	Outer Diameter
OML	Oil Mining Lease
POBM	Pseudo Oil Based Mud
POOH	Pull Out of Hole
PPG	Pounds Per Gallon
PT	Pressure Test
PU	Pick Up
RIH	Run in Hole
RBIH	Run Back in Hole
SAS	Stand Alone Screen
SPDC	Shell Petroleum Development Company of Nigeria Limited
Well AA	Name of the Onshore Well
Well BB	Name of the Onshore Well
WHD	Wellhead
13CR	13% Chromium Stainless Steel

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Laboratory test data obtained from BP Sunbury technical collaboration with M&D.

Other materials for this paper were obtained from TECHDaer, SPDC and M&D internal reports, presentations and studies performed by their internal staff.