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Through-Tubing Sand Control: Innovative Application of an Existing Technology in Rejuvenating Old Wells.

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Abstract
Traditionally, remedial work is carried out on failed Internal Gravel Pack (IGP) completion intervals with excessive sand production by applying one of the following well optimisation options after an economic evaluation:

- *Rig repair to re-install the IGP*
- *Rig repair to side—track well to a better part of the reservoir for news and control installation.*
- *Coiled Tubing (CT) repair to install Through—Tubing (TT) gravel pack (i.e. through 3-1/2'' tubing) in the bottom interval of a well.*

In the process of seeking improved cost-effective repair techniques, a bold initiative was taken to apply an existing sand control technology in an innovative way i.e. through-tubing chemical sand consolidation (SCON) treatment of failed IGP completion in old wells. Three trials were successfully carried cut during the 2019-stimulation campaign in the ForcadosYokri (FY) field and post-repair production test evaluation completed in 1997. Although, a single well trial was also executed in the Escravos Beach field, this paper focuses on the FY trials only.
All the target intervals were located in two-string dual-completion wells while the operation was executed in two broad stages i.e.

- *Pre-SCON stimulation by using a 1-1/4' coiled tubing (CT) work string due to the access restriction in the 2- 3/8" production string installed in one of the wells.*
- *Chemical SCON treatment (overflush system) by bull heading fluids down the production tubing (PT).*

The results of this exercise have been remarkable with an average production gain of ca. 1000 bopd per well while the post repair sand production reduced to less than 10 pounds per thousand barrels (pptb) of gross liquid production. This benefit has translates to a tremendous cost savings of over US$1 Million per well when compared with the conventional rig repair option.
This paper presents a review of the CT/TT repair design, the candidate selection criteria and the operational procedures adopted. The post-repair production results and the actual cost are also compared with predicted well performance and the typical conventional rig repair cost.

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I. Background

The FY field located in Oil Mining Lease (OML) 43 in the Western Swamp depo-belt of the Niger Delta was discovered in 1969 and commenced production in 1970. The field which straddles both offshore and on-shore areas has over 90 development wells with 162 completed intervals (84 producing conduits) while the current field production is 75 Mbopd. All the wells were produced naturally until mid-1999 when gaslift technique was introduced in 11 intervals.

As expected, most of the wells were completed across unconsolidated sandstone formation located in the shallow horizons of the Niger Delta stratigraphy (<6000fttvss). This geological characteristic has informed the prevalent sand control technique applied in the FY field. Approximately 65% of the intervals are gravel packed (74 IGP/28 EGP) completion while the rest are 51 chemical SCON and 5 untreated intervals. Given the relatively low PIs of the IGP completions and the associated pore pressure depletion across the reservoirs, a stress-induced shear failure of the formation rock is sometimes encountered. This usually results in the production of fines and sand along with oil — a situation that usually deteriorates with water production.

All the trial wells were initially completed in 1970 as two- string dual completions during the first phase field development except FY-123 which was completed in 1989. The wells were perforated with big-hole guns (perforation density: 8—12 SPF) and gravel packed with 20/40-mesh gravel which were pumped with HEC-viscosified carrier fluids (see table 2). As a first attempt to reduce the sand production level (sub-critical limit ~ 10pptb), and prevent erosion damage to surface production facilities, the wells were usually beaned down. In certain extreme cases, the wells were completely closed-in, as sand production remained above the acceptable level even at the least available choke size. The consequence of this remedial technique has been the reduction in well potential and the loss of revenue since the wells were produced below their maximum economic recovery (MER) rates. It was against this background that a justification was made for the FY wells' optimisation.

Well Optimisation Process
Review of Past TCITT Projects
Past review of Through-Casing/Tubing Sand Control operations had progressively identified problems and proffered solutions as follows:

- Sub-optimal pre-SCON injectivity test rate due to the simple assumption that a fluid (IPA Brine) injection rate of 3 bpm was; adequate for all reservoirs. This led to SCON treatment being aborted mid-stream when relatively tight' or unclean sand could no longer taken fluids. It was therefore suggested to adopt a new criterion for establishing good injectivity — minimum injectivity index of 3 b/d-psi.
- Incomplete removal of formation damage especially within the perforation tunnels prior to carrying out sand exclusion remedy in the intervals. This led to poor post-SCON production performance in th past because the remain inc damage was inadvertently locked-in place. Pre-SCON acid stimulation was subsequently recommended in order to remove such residual damage. This has also enhanced the successful Injection of all the SCON treatment fluids.
- The use of CT small F string (1.2'' O.D.) imposed a limitation on tile high fluid injection rates required during formation treatment due to tile potential risk of high annular pressures, and CTcollapse Bullhead fluids through production tubing at maximum rate while maintaining sub-fracture pressure was therefore recommended.

The above lesson were expectedly beneficial in the successful planning and execution of the new SCOMN remedy for the damage FY IGP completion.

Well Diagnosis and Candidate Selection
Preliminary candidate selection was based on the modified screening criteria For through—casing chemical SCON operations with additional consideration made for the CT'accessibility. The following were therefore useful in selecting the selecting

- Clay Content less than 25%
- Length of perforation interval less than 14 ft
- Bottom Hole Temperature between 101 -- 1 85 ^{o}F
- Formation Fluid Salinity less than 3% v/v
- Developed Ultimate Recovery more than 0.5 MMSTB.
- Absence of any recompletion/repair prospect below the existing well completions.

After a comprehensive review of tile well production history and mechanical data, final candidate selection was aided by the use of an in-house well diagnostic software tool - well performance simulator. The expected post-repair performance was optimised by carrying out production sensitivity analysis on reduced drawdown and increasing PIs within the simulator, since drawdown reduction reduces the potential risk of sand production Three wells were finally selected for the initial trials i.e. FY-28, FY-32, and FY-123

Well/Job Treatment Design
For the pre-SCON acid stimulation, treatment volumes (table 3) were designed based on the following dosage per foot of perforation:
Preflush (7.5% HCI Acid): 50 gal/ft
Mainfiush (6% HCI + 1.5% HF): 70 gal/ft
The volume of the preflush was kept relatively low (50 gal/ft) due to the low carbonate content of the Niger Delta sands. In order to avoid degradation of the near wellbore formation, half strength regular mud acid (RMA) was used as the mainflush. The acid mainflush was displaced with diesel containing a mutual solvent treatment so as to aid acid back-production and well clean-up.
For the FY-285 interval, a relatively large volume treatment was anticipated because of the perforation length (> 10 feet). Hence, overflush fluid (3% NH4CI Brine + Surfactant) treatment dose of —70 gal/ft was used to displace acid mainflush deep into the formation since the acid was not back-produced. Foam diverter was also used in order to ensure that the entire interval was adequately treated.
For the chemical SCON treatment, volumes were computed using a pre-designed spreadsheet based on a radial propagation of treatment fluid into the near wellbore (See appendix I and figure 1). Since the overflush was designed to displace the excess resin from the formation pores and control the plastic film thickness, this fluid

was ii major determinant of the final compressive strength and the corresponding return permeability attained. The overflush volume, Vu was therefore twice the treatment volume (i.e. Vo= 2Ve).

Operations Procedure & Problems
Given the similarity to previous rigless repair operations, the new technique was executed with a minor variation as per the following procedure:

1. Sub-surface safety valve was retrieved, and a dummy installed with wireline.
2. CT was run in hole to end of production tubing while circulating well to clean brine.
3. CT/PT were pickled with 100 gallons of solvent (xylene) and 300 gallons of 15% HCI acid in order to remove rust and scales from the tubings. Thereafter, well was circulated to diesel.
4. With CT tail positioned at top perforations, the acid was mixed and pumped via CT.
5. Acid was flowed back and well produced clean (acid returns were treated and neutralised with soda ash before being pumped to flowstation)
6. After pulling out the CT. all chemical SCON materials were mixed and bullheaded at maximum rate while maintaining pressure below fracture pressure.
7. Well was shut-in for 48 hours while resin cured at bottom hole conditions.
8. Interval was opened-up on bean 16/64”
9. A drift run was made with wireline to ensure that the tubing bore was free.
10. The sub-surface safety valve was re-installed and conduit restored to production.

Each TT-repair operation was estimated to take a duration of ca. 6 days from CT barge arrival on location to demobilisation (2 days allowed for spudding jack-up barge legs, ballasting and deballasting).

Failure Potential & Risk Assessment
Two major concerns considered prior to the project execution are indicated as follows:

- **The possibility of the congealed resin forming a bridge between the wire-wrapped screen and the gravel pack.**This is because additional bonding strength of the downhole completion could increase the risk of workover failure by making the IGP assembly retrieval more difficult during future well re-entries. The importance of evaluating this risk was underscored by historical evidence of difficult gravel pack retrievals in SPDC workover operations. Recent statistics have shown that average retrieval time for single-interval IGP completion in the relatively old wells is Ca. 5 days. For wells without any scope for future re-entry e.g. where existing recompletion prospects are located at shallower intervals, the risk was considered negligible. In all the trial wells, there were no recompletion opportunities.
- **The possibility of the flow paths or wire mesh slots (0.012” Gauge) of the wire-wrapped screen being blocked when it comes in contact with the resin.** It was reasoned that since the contact time was going to be very minimal while the resin was being overdisplaced. the resin would not set on the screen but in the formation. This risk was also deemed manageable since the wire-wrapped screen can be perforated through-tubing to re-establish communication with the formation in the event of a complete screen-seal’.

Economic Evaluation & Project Ranking
All the wells were evaluated based on the SPDC principles of economic analysis for low-cost, short-term oil (STO) optimisation projects. This spreadsheet analytical approach integrates the CAPEX and OPEX costs (at a discounting factor of 8% over the lifetime of the production gain) to compute a unit technical cost (UTC) per barrel of oil gain. A 3-year linear decline in production gain was assumed with zero production at the end of the period. The projects were subsequently ranked against others in the STO activity portfolio. Execution of the threetrial projects was however given a high priority during the FY stimulation campaign in order to adequately test the feasibility of the new technique. Table 1 gives the planned and actual cost performance of the well trials.

Table-1: CT/TT-SCON Repair Cost Data

	Planned		Actual	
Well/Sand	*Cost , $,000	UTC, $/bbl	*Cost , $,000	UTC, $/bbl
FY-28S/D6.0L	220.0	2.23	182.3	1.44
FY-32L/D8.0K	129.0	1.82	232.9	1.81
FY-123L/D9.4L	178.2	2.25	223.1	1.86
Average per job	162.0	2.10	212.8	1.70

***CAPEX only (CT-Barge/Chemicals/Service charge)**
Estimated rig-IGP repair cost ~ $1.8 Million

Although the average actual well cost was higher than estimated, the final UTCs were lower than predicted due to the higher than expected production gains (table 4) realised from the well repairs. UTC of $2.00/bbl is used as the cut off limit for justifying STO activities.

Case Histories/Results

Forcados Yokri-28S1D6.OL

The interval was initially completed as 2-string dual producer (E2.0 and D6.0 sands on the long and short strings respectively) after a chemical scon with the old single-phase epoxy resin system in August 1970. Well came on stream in February, 1971 but was re-entered with a rig in May 1990 for mechanical repairs i.e. change-out of obsolete completion equipment, extension of existing perforation intervals and installation of IGP across the two intervals. The post-workover production of the D6.0 interval was very poor (<300 bpd on bean 20/64”) and hence, interval was stimulated in January 1993. Interval production (fig. 2 & table 4) remained unsatisfactory due to persistent sand production (peak 43 pptb) and hence, conduit choke size was restricted to 20/64”.

Interval was stimulated and sand consolidated in July 1996. 900 gallons of half strength RMA was pumped into the perforations in two stages while 3% Nitrified Ammonium Chloride brine mixed with surfactant was used as diverter before the second stage pumping. 28 barrels of the epoxy resin mixture was used to treat the formation and repair the failed gravel pack interval. Interval production as at end 1997 was 1940 bopd on bean 44/64”

Forcados Yokri-32L/D8.OK

This, well was initially completed as 2-string dual producer (D8.0 and D5.0 sands on the long and short strings respectively) after the sands were consolidated with the old single-phase separating system in December 1970 and came on stream in February 1971. Well was re-entered with a rig in November 1974 for sand-exclusion repair (perforation extension and a chemical scon) on the D5.0 interval and in March 1983 for IGP installation across the two intervals. The post-workover production from the D8.0 remained poor even after acid stimulation in December 1992. Interval production (fig. 3 & table 4) was subsequently restricted (530 bpd on bean 28/64”) in order to reduce sand-cut which remained above 10 pptb.

Interval was stimulated with 700 gallons of half strength RMA prior to sand consolidation in July 1996. 22 barrels of the epoxy resin mixture was used to treat the formation and repair the failed gravel pack interval. Current interval production was 1430 bpd on bean 32/64” with BS&W — 20%.

Forcados Yokri-123L1D9.4L

Unlike the other wells which were much older, this well was initially completed in October 1989 as 2- string dual producer (D9.4 and D3.0 sands on the long and short strings respectively) with IGPs. The D9.4 interval came on stream in December 1990 but the production (figs. 4. 5 & table 4) was restricted (gross rate of 950 bpd on bean 36/64”. BS&W — 0%) due to excessive sand production (peak level - 24 ppth).

As in the previous wells, interval was stimulated with 700 gallons of half strength RMA prior to a chemical SCON in April 1996 making it the first well trial. Approximately 25 barrels of the epoxy resin mixture was used to treat the formation and repair the damaged IGP interval. The interval produced thereafter with a maximum gain of ca. 700 bopd for 4 months withthe BS&W rising to 46%. Interval was confirmed dead after it failed to produce even after repeated swabbing and has been closed-in since October 1996.

Problems Encountered

Quality control (QC) was a challenge since the epoxy resin B component was observed to the separating, apparently due to long storage in the warehouse. Consequently, adequate QC check was carried, out before chemical transport to the field in addition to on-site agitation.

Re-installation of the sub-surface safety valve in the production conduit was impossible after the first scon treatment at FY-123L apparently because of epikote blocking the control line bore. This led to a decision to continuously flush the line with hydraulic fluid during subsequent trials so as to ensure adequate communication for operating the safety valve mechanism after the scon exercise. One alternative preventive action considered was the installation of a dummy in the safety valve profile prior to every scon treatment. However, this was deemed unattractive, given the risk (e.g. loss of bottomhole tool assembly or wire parting) associated with multiple wireline re-entries in the production tubing.

II. Conclusions

- Through-tubing application of chemical SCON treatment in failed IGP completions has been proven to be a highly feasible cost-effective sand-exclusion remedial technique. Both short and long string intervals in dual and multiple zone well completions have been successfully treated in the FY field.
- In terms of post-stabilisation production gain, two of the three treated intervals were highly successful with average production gain of over 1000 bopd.
- The production performance improvement of the ForcadosYokri IGP completions is attributed to the combined effect of pre-SCON acid and chemical SCON treatment which allowed intervals to be beaned up to their optimum potentials without exceeding the critical sand production limit.
- Pre-shipment QC test and agitation of the SCON chemicals ensured the utilisation of only homogeneous products in the field. Additional performance improvement could have been achieved by optimising the acid treatment design since a uniform recipe was applied in all the trials, irrespective of the reservoir mineralogy. Application of fluid compatibility test results and the use of new stimulation software are expected to aid subsequent design in specific environments.
- Although the cause of the relatively poor performance of FY-l23L/D9.4L interval has not been fully understood, preliminary evaluation suggests that a preferential stimulation of the water leg might have occurred as reflected by the rapid increase in post- repair water production. Among the three trial wells, the FY-123L/D9.4L interval presented the most unfavourable wellbore environment (i.e. highest bottom hole temperature, clay content and formation water salinity) for the SCON-treatment application. Further investigation will be required to confirm this diagnosis.

Future Plans

Scope for application of this new technology in our environment is limited because most IGP/EGP completions were installed across thick oil sands with longer-than 14-foot perforation intervals. However, we' plan to continue evaluating the capability of this technique in other wells that meet the screening criteria when they start cutting excessive sand.

Nomenclature

BS&W - *Base Sediments and Water*
CAPEX - *Capital Expenditure*
Current - *refers to 1st January 1998*
EGP - *External Gravel Pack*
Epikote - *Cured Epoxy Resin*
HEC - *Hydroxyl Ethyl Cellulose*
IGP - *Internal Gravel Pack.*
IPA - *Iso-propyl alcohol*
OPEX - *Operating Expenditure*
PI - *Productivity Index, b/d-psi.*
SPF - *Shots Per Foot*

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3. Nguyen, P.D. et al: "New Guidelines for Applying Curable Resin-Coated Proppants" paper SPE 39582 presented at the 1998 International Symposium on Formation Damage Control, Lafayette, Louisiana, Feb. 18-19.
4. Boham, D.S.: "Economics of Production Optimisation in the Nigerian Fiscal Framework" paper SPENC 9714 presented at the 1997 SPE (Nigeria Council) Conference and Exhibitions.

Table-2: Reservoir Rock/Fluid & Completion Data

INTERVAL/SAND	FY-28S/D6.0L	FY-32L/D8.0K	FY-123L/D9.4L
Reservoir Rock/Fluid Data			
Net Oil Sand, NOS - ft	56	35	144
Oil Density, ρ_o - ^oAPI	24.3	25.2	25.5
Reservoir Datum, H - ft tvss	5160	5400	5370
Formation Permeability, K - mD	4840	1130	1230
Formation Porosity, ϕ - fraction	32	28	30
Clay/Shale Content, V_{shale}- %	16	10	25
Initial Reservoir pressure, P_i- psig	2260	2350	2175
Current Reservoir pressure, P_{rc}- psig	1968	2170	2028
Water Saturation, S_w - fraction	19	19	19
Oil viscosity (res. condition), μ_o- cp	1.90	1.40	1.60
Formation Volume Factor, B_o- rb/stb	1.144	1.153	1.169
*Formation Fluid Salinity, - ppm Cl^-	17,800	19,100	19,500
Bottom Hole Temperature, T_b- ^oF	155	158	166
IGP Completion Data			
Open Hole/Bit Diameter, D_w- in	12.25	12.25	8.5
Production Casing size, r_w - in	9-5/8	9-5/8	7
**Perforation Depth Interval,- ft ahbdf	5214-5228	6336-6344	5960-5970
Perforation Depth Interval, - ft tvss	5166-5180	5408-5416	5377-5385
Perforation Length, H_p - ft tv	14	8	8
Well Deviation at completion, - deg	3/4	30	37
Perforation Gun Diameter, - in	7-1/4	5	5
Perforation Shot Density - SPF	12	8	12
Gravel Pack Liner O.D, - in	5-1/2	7	4
Production Tubing O.D, - in	3-1/2	3-1/2	2-3/8

**Fluid Salinity Cut-off (3% vol/vol=53,600 ppm Cl⁻)* ***Along hole below derrick floor*

Table-3: Treatment Fluid Data

INTERVAL/SAND	FY-28S/D6.0L	FY-32L/D8.0K	FY-123L/D9.4L
Tubing Pickle Treatment			
Solvent - gals	100	100	100
15% HCl + Inhibitor - gals	300	300	300
Matrix Acid Treatment			
Pre-Flush (7.5% HCl + Additives***) - gals	700	500	500
Main-Flush (Half-Strength RMA + Additives***) - gals	900	700	700
Overflush (3% NH_4Cl Brine + Surfactant) - gals	1000	0	0
#Diverter Fluid (NH_4Cl Brine + N_2 + Surfactant) - bbls	3	0	0
Displacement Fluid (Diesel + solvent) - gals	1100	1100	1100
Chemical SCON Treatment			
Pre-Flush (Diesel + Surfactant) - bbls	32+32	22+22	26+26
Blanket (Diesel + Solvent) - bbls	16+16	11+11	13+13
Epoxy Resin Mixture (A&B) - bbls	28	22	25
Overflush (Diesel + solvent) - bbls	42+21	30+15	36+18
Displacement Fluid (Diesel) - bbls	25	25	25

****Additives volume not included in figures quoted.*

#Diverter fluid used between two stage-application of acid treatment in FY-28S only.

Table-4: Production Performance Data

INTERVAL/SAND	FY-28S/D6.0L	FY-32L/D8.0K	FY-123L/D9.4L
Pre-treatment			
Bean - /64"	20	28	36
Gross Production - bpd	260	530	950
Water Cut, BS&W - %	0	10	0
Net Production - bopd	260	480	950
Peak Sand Production - pptb	.43	86	37
Post-treatment			
Bean - /64"	44	32	36
Gross Production - bpd	1910	1430	1710
Water Cut, BS&W - %	2	20	0
Net Production - bopd	1910	1140	1710
*Sand Production - pptb	6	8	8

**Post-stabilisation peak sand cut*

Appendxi-1

Chemical Sand Consolidation

The main philosophy of the chemical scon system is to arrest sand production with minimum adverse effect of production loss. There are two types of the epoxy-based consolidation system, which have been progressively applied in our operations i.e.:

- The single phase separating or placement system was the first developed version of the Shell's chemical scon system. Although, it utilises four component additives thereby complicating treatment mixture formulation, major advantages were its optimised placement properties.
- The epoxy resin-based overflush system as the name implies, utilises a non-reactive overflush fluid in addition to two other reactive components. These are further described as follows:

(i) Reactive epoxy resin
(ii) Reactive curing agent
(iii) Non-reactive overflush

This system has been considered more favourable because it can tolerate higher clay content (up to 20%) and is safer to handle.

Calculation of Treatment Volumes

This calculation is based on the following us assumption:

- There is a radial propagation of the treatment fluid into the formation such that the treated weilbore vicinity cylindrical in shape with a hemispherical top and bottom.
- Consequently, the pore volume can be calculated accurately as a function of interval length, penetration depth, formation porosity and permeability as follows:

Pore/treatment Volume,

$$Ve = \phi\pi(R^2 - R_W^2)H + \phi.(4/3)\pi(R-R_W)^3$$
$$= \phi\pi(HD + 2HR_W + 1.33D^2 * K_V/K_h)$$

where

ϕ = porosity

D = depth of penetration

H = length of perforated interval

R_W = wellbore radius

R = radius of propagation (R_W + D)

K_V/K_h = ratio of vertical to horizontal permeability

Table-4: Production Performance Data

		INTERVAL/SAND		
		FY-28S/D6.0L	FY-32L/D8.0K	FY-123L/D9.4L
Pre-treatment				
Bean	- /64"	20	28	36
Gross Production	- bpd	260	530	950
Water Cut, BS&W	- %	0	10	0
Net Production	- bopd	260	480	950
Peak Sand Production	- pptb	43	86	37
Post-treatment				
Bean	- /64"	44	32	36
Gross Production	- bpd	1910	1430	1710
Water Cut, BS&W	- %	2	20	0
Net Production	- bopd	1910	1140	1710
*Sand Production	- pptb	6	8	8

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Appendix-i

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$$= \phi\pi(HD + 2HR_w + 1.33D^2 * K_v/K_h)$$

where

ϕ = porosity

D = depth of penetration

H = length of perforated interval

R_w = wellbore radius

R = radius of propagation (R_w + D)

K_v/K_h = ratio of vertical to horizontal permeability

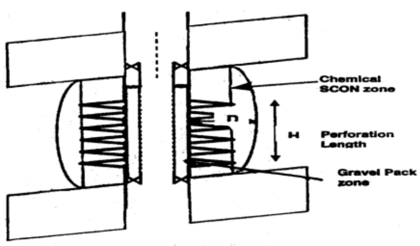


Fig. 1 - Chemical SCON Treatment - for Internal Gravel Pack completion

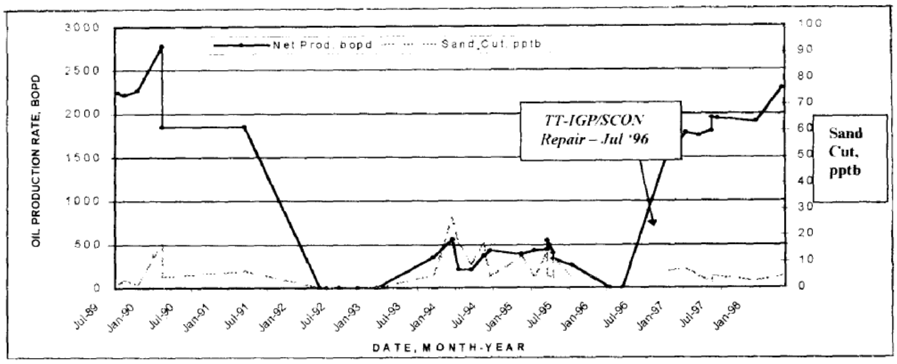


Fig. 2 – FY-28S/D6.0L Interval Production Performance

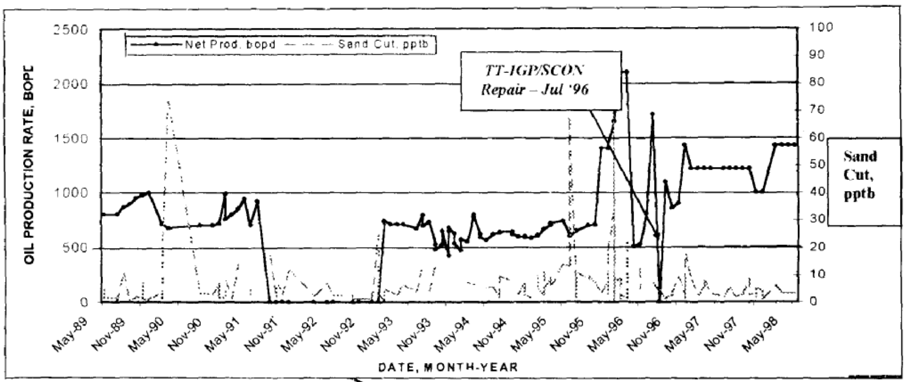


Fig. 3 – FY-32L/D8.0K Interval Production Performance

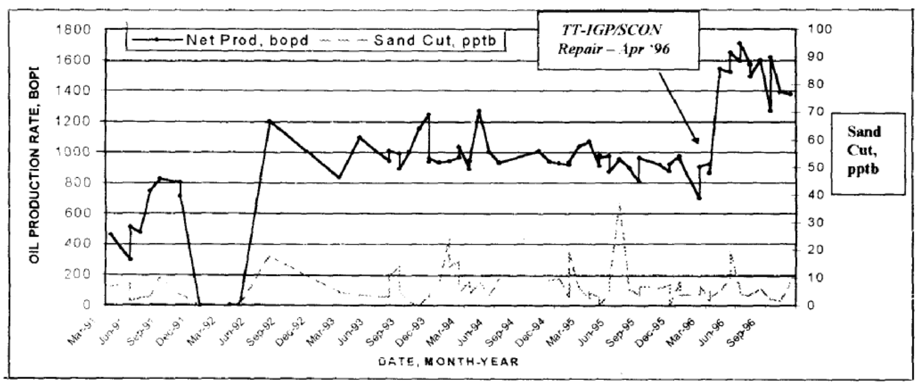
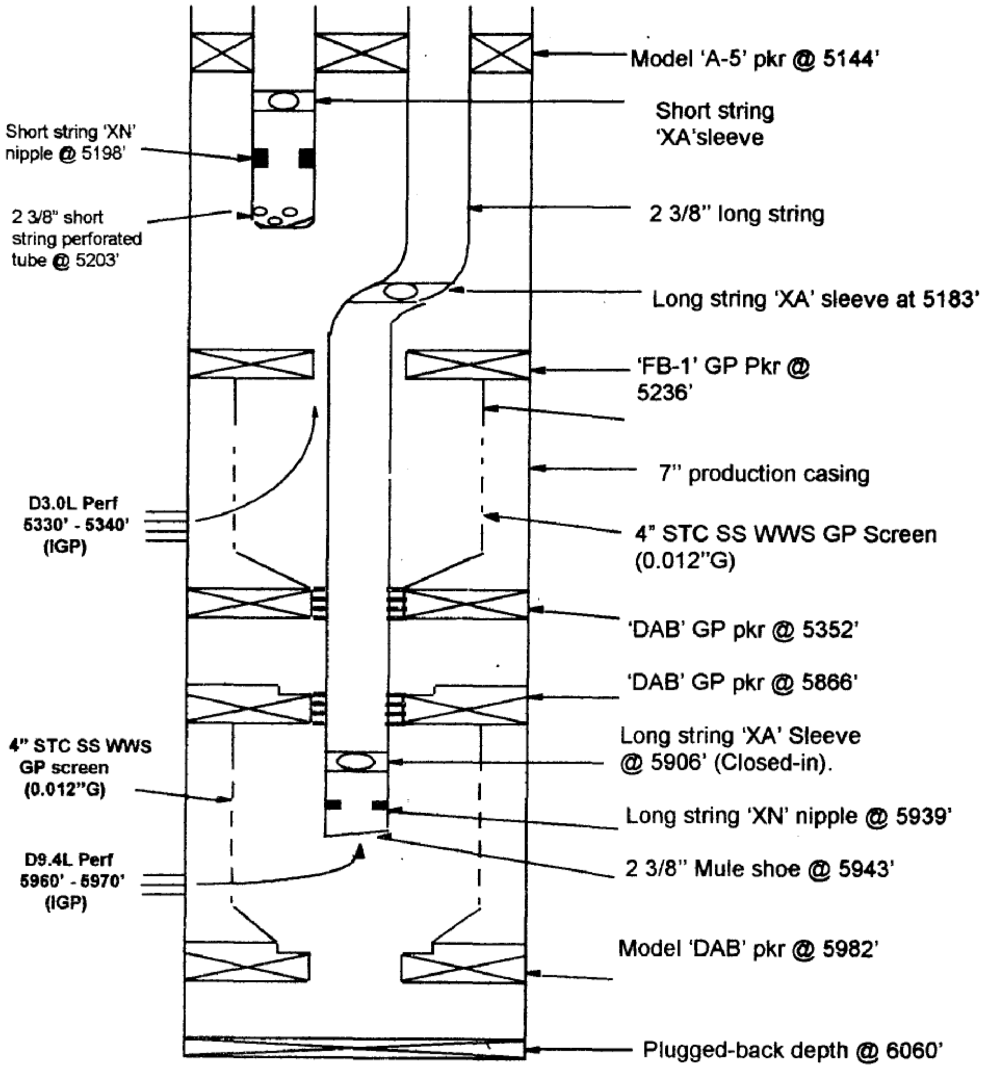


Fig. 4 – FY-123L/D9.4L Interval Production Performance

Fig. 5 - FORCADOS YOKRI-123 WELL COMPLETION SCHEMATIC



I.B: All depths are along hole.

Objectives/Highlights

- *Sand exclusion repair of D9.4L (IGP) Interval.*
- *Enhance production with a pre-SCON Stimulation.*
- *First SCON treatment of an existing IGP Completion in SPDC.*
- *Estimated Repair Cost/Initial Production Gain - USD 0.18M/300 BOPD.*
- *Conventional Rig Repair Cost - USD 1.8M*
- *Execution Date - April, '96.*

Society of Petroleum Engineers, Nigeria Council - 1998

Akpoturi Peters. "Through-Tubing Sand Control: Innovative Application of an Existing Technology In Rejuvenating Old Wells." *International Journal of Engineering and Science*, vol. 12, no. 12, 2022, pp. 40-49.