SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

DIEBU CREEK 1L
RE-PERFORATION AND SCON PROPOSAL
(FLOWLINE REPLACEMENT REQUIRED)

Document number:	SPDC-2019-05-00000276	**Prepared By:**	David Olayinka/Imorame Imonitie – PP Unukogbon Obaro – PG Nwosu Obiora – PT Sa'ad, Abdul-Wahab – RE Esther Briggs – WRFM Jimba, Olugbenga – Asset Engineering
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I. TABLE OF AUTHORISATION

REVIEWED/ ASSURED BY:

Name	Position
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Name	Position	Signature
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II. TABLE OF CONTENT

1. OBJECTIVE:

WELL:	**DIEBU CREEK – 001L**
TYPE:	Re-Perforation, SCON and FLRR Proposal
OBJECTIVE:	To restore production on Diebu Creek 001L on the E9500N sand by carrying out re-perforation, chemical sand consolidation and flowline replacement. This activity is expected to unlock a potential of 450 bopd and safeguard resource volume of 0.87 MMStb.

2. WELL HISTORY/ PRESENT STATUS:

DBUC 001L (E9500N): [11856 – 11860 ftah, 11791 – 11795 ftss] TT SCON

DBUC-001 was drilled and suspended in December 1966. The interval came onstream on the E9500N reservoir with an initial offtake of 320 bopd and attained peak production of 1150 bopd in October 1973 (GOR 1505 scf/day, BSW 32.6%, sand cut 3pptb).

Water production started at initial well start-up (suspected to be completion brine) and later receded. In March 1975 the interval was reported to have quit production and there is no documented reason on why the interval quit production. Last Rate: 508 bopd, 20% BSW, GOR 1086 scf/bbl. During closed-in wells review, it was recommended that this interval be re-perforated, SCONED and opened to production.

Latest well head pressures from Preventive maintenance in February 2019 show CITHP of 200psi and CHP of 0psi.

3. PROPOSED ACTION AND JUSTIFICATION:

DBUC001L is the only completion on the E9500N reservoir block that encountered hydrocarbon thus, there is no other existing well penetration that can develop the remaining volumes in the E9500N. Historical production showed that the interval produced sparingly for ca. 19 months before experiencing a sharp decline in the Tubing Head Pressure (THP), causing the well to quit production. The Interval has produced about 9% of STOIIP, and there is some remaining 0.87 MMbbl of contingent resource to be developed through this interval.

The E9500N reservoir has a base case STOIIP of 4.4 MMstb. The top structure map (Reference Appendix 9) indicates that the size of the hydrocarbon accumulation is small relative to the size of the aquifer. The reservoir pressure acquired indicates ca.18psig (0.4%) decline with minimal liquid withdrawal (Cumulative production of 0.36MMbbl).

The MBAL model energy plot in Appendix 8, shows the dominant drive mechanism to be aquifer. Although the reservoir pressure decline at the early stages of production suggests a delayed aquifer response, the aquifer responded with a re-pressurization as seen in the acquired bottom hole pressure data. An increased perforation extent will benefit the well in terms of better inflow.

It is proposed to carry out re-perforation across the interval from11844 – 11850 ftah and 11854 – 11860 ftah to increase the inflow area and improve the productivity on the zone (Reference Appendix 5). Current perforation interval is 11856 – 11860ftah. Flow line re-placement (FLLR) will also be carried out as the flowlines have been stolen. DBUC001L was initially completed with SCON. Historically, the sand cut averaged at 5 pptb which is considered below the Shell cut-off of 10pptb. To forestall future sand production from the new perforations, the interval will be treated with SCON as remedial sand control.

4. PROPOSAL SUMMARY

1. Re-perforate the 4ft. existing interval on the E9500N sand and add extra 8ftah above the current perforations (Total perforation interval of 12ft; 11844 – 11850 ftah & 11854 – 11860ftah).
2. Deploy SCON across the entire perforations and allow to cure.
3. Open well to flow.
4. Hand back well to Production.

5. SCON RECIPE

Analysis of Diebu Creek wells historical performance suggests that sand control is required to maintain the sand below the acceptable limit of 10pptb to safeguard the well equipment and facilities. Although the depth of the target sand is >10,000 ft-tvd, Chemical Sand Consolidation (SCON) will still be deployed as a sand exclusion mechanism to sufficiently retain the formation sand post perforation extension

Chemical Sand Consolidation Fluid Schedule and Perforation Details:

NB: Preliminary Sand Trap 225 Schedule – E9500N Interval

Fluid Schedule –	Rate	E9500N – 12 ft perforation
Preflush 1 – 100 gal/ft.: 7% KCl + 0.5% ES 5	1.0 bpm	28.57 bbl.
Preflush 2 – 100 gal/ft.: Musol	1.0 bpm	28.57 bbl.
Main Treatment – 150 gal/ft.: Sand Trap 225 resin	1.0 bpm	42.86 bbl.
Spacer – 100 gal: Diesel	1.0 bpm	2.4 bbl.
After flush – 150 gal/ft.: 7% KCl + 0.5% ES 5	1.0 bpm	42.86 bbl.
Displacement	1.0 bpm	CT Volume

Perforation:

The perforation depths were selected based on evaluation of open hole petrophysical logs, to increase the area available for well inflow. (Reference Appendix 5).

	Existing Perforation (To be re-perforated)		**Proposed Perforation**	
Reservoir	ftah	ftvdss	ftah	ftvdss
E9500N	11,856 – 11,860	11,791 – 11,795	11,844 – 11,850	11,779 – 11,785
			11,854 – 11,856	11,789 – 11,791

Note:
- The existing interval (4ft) will be re-perforated and 8ft of new perforations will be added across the E9500N during the STOG activity.
- Perforation is a safety critical operation and must be conducted in line with all required safety precautions during gun arming, running in hole and pulling out of hole.

The proposed intervals will be perforated overbalance using a deep penetrating gun, 60 deg. phasing, 6 shots per foot.

6. POTENTIAL ESTIMATION

The well performance evaluation software, PROSPER, was used to determine the potential for DBUC-001L on the E9500N reservoir. The model was matched/calibrated to the last production performance of the well in March 1975 and based on historical performance, a specific PI was derived and applied to the proposed 12 ft perforations. Water cut of ca. 20% was assumed considering the expected breakthrough of water post intervention. Sensitivity on different choke sizes was made (16/64" to 20/64") while noting the impact on the drawdown applied to the reservoir. Bean 16/64" potential was used for the economic and technical evaluation of this activity resulting to a net oil potential of ca. 660 bopd.

A risk factor of 70% was applied to the net potential based on OP18 premise for NFA (WO) technical risks assumptions on historical success rate for Perforation Extension and Chemical Sand Consolidation (SCON) and the risk of high gas production was also considered resulting to a risked potential of 450 bopd.

7. RESOURCE ESTIMATION

Interval	**Reservoir**	**Planned DUR (for the interval)- MMstb**	**Np (for the interval) MMstb**	**Contingent Resources/Reserves to be Developed by activity- MMstb**		
				Low	Best	High
DBUC 001L	E9500N	1.23	0.36	0.51	0.87	0.97

8. WELL & RESERVOIR DATA SHEET

S/N	WELL/ SAND:	UNIT	Disc.	DBUC001L (E9500N)
1	a) Existing Perforated interval b) Existing Perforated interval c) Proposed Perforation interval d) Proposed perforation interval	ftah ftss ftah ftss	PP	11,856 – 11,860 11,791 – 11,795 11,844 – 11,850; 11854-11860 11,779 – 11,785; 11789 – 11795
2	a) Maximum Deviation Angle and Depth b) Derrick Floor Elevation c) Vertical Correction to mid- Perforation + DFE	° @ ft ft fttvd	PG	5.7° @ 6251 50.6 11843.6
3	a) Last Production Rate	bopd	PT	508 bopd @ March. 1975
4	a) Reference Depth for Reservoir Pressures b) Original Reservoir Pressure * c) Present Reservoir Pressure d) Present Gradient e) Bubble Point Pressure f) Specific Gravity of Oil 60/60 g) Oil Viscosity at Reservoir Condition h) Solution Gas-Rsi (initial condition) i) Formation Volume Factor (initial condition) j) Static Reservoir Temperature	ftss psig psig psi/ft psig SG cP scf/stb - ° F	RE	11780 5115 5082 0.431 5115 0.85 0.33 1546 1.695 204
5	a) Other Wells Producing from the same Block b) Last production from Block (@ Mar. 1975) c) Ultimate Recovery (@ Dec. 2018) d) Cumulative Production from Block (@ 1.1.2019) e) Cumulative Production from Well (@ 1.1.2019) f) Remaining/Dev Reserve from Well	- bopd MMstb MMstb MMstb MMstb	RE/PT	1 508 1.23 0.36 0.36 0.87
6	a) Porosity b) HC Saturation c) Permeability d) Sand Thickness as per PDL e) Net Oil Sand f) Net/Gross Ratio g) Original estimated GOC in Well (or Reservoir) h) Present estimated PGOC in Well (or Reservoir) i) Change in GOC from original GOC j) Distance Between Highest Perforation and PGOC	% % mD fttvd fttvd ftss ftss ftss ft ft	PP	0.24 0.54 1620 45 38 0.84 N/A (OUT @ 11762ftss) N/A N/A N/A
7	a) Original Estimated OWC in Well (or Reservoir) b) Present Estimated OWC in Well (or Reservoir) c) Change in OWC From Original OWC d) Distance Between Lowest Perforation and POWC	Ftss Ftss ft ft tvd	PP	11804 (ODT) NA N/A 9 (ODT)
8	a) Tubing Size/Weight b) Casing Size/Weight c) Liner Size/Weight	in/ibs/ft in/ibs/ft in/ibs/ft	PT	3-$^{1}/_{2}$" / 9.3 9-$^{5}/_{8}$" / 47 7" / 32
9	a) Average Hole Size across Completion Interval	in	PP	8.5
10	a) Is there a barrier between top of completion Interval and the present estimated GOC. b) Is there a barrier between lowest completion Interval and the present estimated OWC		PG	Yes N/A

NA – Not Available, N/A - Not Applicable

9. RECENT WELL TEST DATA

Well	Date	Choke	BS&W	Gross	Net	GOR	Sand	FTHP	CHP
DBUC001L	September 1974	16	0	759	758	2039	1.3	2262	0
DBUC001L	October 1974	16	0	775	775	2168	0.8	2262	0
DBUC001L	November 1974	16	0	773	771	1764	1.5	2227	0
DBUC001L	December 1974	16	0	774	772	1347	1.9	2002	0
DBUC001L	January 1975	16	3.7	848	816	1067	1.6	1782	0
DBUC001L	February 1975	16	4	849	815	1058	0.8	1764	0
DBUC001L	March 1975	16	20	635	508	1086	1.3	1400	0

10. COST ESTIMATE

The total cost of the 0.7 KM flowline replacement **is $365,932.31** while the total cost of the Perforation Extension and SCON is **$1,703,300.81**

S/N	DBUC 1L, PERF, SCON, N2 LIFT	$
1	Mobilization	255,442.48
2	WHM package	29,100.00
3	Slickline package	29,250.00
4	Coiled Tubing Package	213,504.61
5	Swamp Logistics	545,685.00
6	Sand Trap (12ft interval)	158,400.00
7	QA/QC Engineer	11,964.00
8	Perforation	105,000.00
9	Chemicals (salts)	83,087.00
10	Liquid Nitrogen (2 tanks)	32,000.00
11	Demobilization	63,860.62
12	FTO/Security	75,707.10
13	AGO	20,800.00
14	Crew Flight	24,000.00
15	OH personnel	10,500.00
16	CCU Actuator / Control Panel	45,000.00
17	**Total**	**1,703,300.81**

11. HSSE/ SPECIAL WELL/LOCATION CONDITION

CONDITION OF WELLHEAD	Ok
ANNULUS PRESSURE MEASUREMENT/DATE	CHP A = 0psi.; CHP B = 0psi. (03/02/2019)
MAASP / MAWOP	80 bar / 60 bar (A-annulus), 13 bar / 10 bar (B-annulus)
WELL INTEGRITY SUMMARY	Well has no integrity issue.
CONDITION OF PRODUCTION STRINGS	Both Strings are ok
ANY PROBLEM DURING PRIMARY CEMENTATION OR LAST RE-ENTRY	No
SPECIAL FISHING TOOL REQUIRED	No
LOCATION CONDITION	Ok
COMMON CELLAR	No
SEASONALLY FLOODED	Yes
SIZE LIMITATION	No

12. RISKS AND MITIGATION

RISKS	TECOP	LIKELIHOOD/ IMPACT	IMPACT	MITIGATION/MANAGEMENT
Loss of well control during intervention.	Operational	M/H	▪ Well kick ▪ Spills into the environment ▪ Fire/blowout ▪ Company reputation	▪ Use of appropriately rated PCE (Wireline BOP/ lubricator) ▪ Robust pore pressure and fracture gradient predictions has been made to indicate expected reservoir pressure.
Well unable to flow due to insufficient lift post intervention activity.	Technical/ Operational	L/H	▪ Delay in OSD & cash flow deficit post intervention activity. ▪ Rig-less intervention cost escalation.	▪ Ensure adequate planning with robust contingency for N2 lift post intervention. ▪ Lift entire tubing capacity plus volume of fluid pumped into the wellbore.
Well unable to sustain flow for an extended period due to reservoir pressure depletion. In addition there might be early ingress of water, as seen in early production history (although suspected to be completion brine) and this has been considered in the risking of the potential.	Technical	L/M	▪ Potential impact on recovering of resources.	▪ Ensure that the withdrawal is managed to allow the aquifer to kick in.
High associated gas production after Perforation activity	Technical	H/H	▪ Potential impact on well rates if GOR creaming is required. ▪ Cost implication resulting from increase in Gas flaring penalty.	▪ Optimal bean control/ GOR creaming will be used to mitigate excessive AG production. ▪ Well offtakes will be managed to produce well at acceptable Rsi limit (3*Rsi).
Potential for drop objects during Well Intervention operations	Technical/ Operational	H/H	▪ Potential for Near misses and/or injury to personnel. ▪ Inability to continue the workover operation based on the severity of the above impact.	▪ Ensure DROP zones are identified prior to operations and proper barriers are in place. ▪ Ensure strict adherence to JHA and PTW processes during operation.
Possible HUD inside Tubing	Technical/ Operational	M/H	▪ Inability to access sand face to stimulate interval. ▪ Impact on intervention cost from excessive time spent on removing restriction.	▪ Drift tubing and tag XN prior to job execution. ▪ Run LIB if HUD is encountered to confirm nature of HUD. Contact PTW/O/NG or UPO/G/UVC ▪ Mobilize necessary fishing/ jetting tool to manage hole restriction/ HUD during operation.
Contamination risk from SCON chemicals.	Technical	L/H	▪ Tubing restriction if SCON chemical congeals during deployment impacting well promise and cost. ▪ HSSE impact from exposure to SCON chemicals.	▪ Proper chemical compatibility test and appropriate field supervision during SCON deployment. ▪ SCON chemicals should be properly bulked in the contractor's base and transported to the field locations

RISKS	TECOP	LIKELIHOOD/ IMPACT	IMPACT	MITIGATION/MANAGEMENT
				▪ Ensure all connections are pressure tested and leak tight before pumping SCON chemicals ▪ STOP work authority to be in place to avoid any HSE exposure during SCON treatment. ▪ Unused chemicals should be returned to contractor base for proper disposal.
Tubing burst during pressure test.	Technical/ Operation	L/M	▪ Prolonged well operation and increased cost.	▪ Clearly define maximum allowable burst load and maximum allowable surface test pressure for the tubing.
Exposure to NORM	Technical/Organizational	L/H	▪ Health hazard to staff. ▪ Environmental and reputational impact and additional cost for clean-up.	▪ Safety measures as stipulated in the HSSE and SP Control Framework (Ionizing Radiation Manual) should be followed. ▪ A radiation protection officer should be appointed for the operation. ▪ Ensure exposure control and adequate dosimetry. ▪ Appropriate PPE should be worn by staff handling tubulars and other well accessories.
Community Issues	Political	M/H	▪ Delays in well execution/ increased cost.	▪ Early engagement as per SCD / MoU. ▪ Ensure FTO is secured prior to commencement of operations.
Security	Political	M/H	▪ Delays in well execution/ increased cost.	▪ Security surveillance and intelligence evaluation should be conducted prior to equipment mobilization to site. ▪ Follow Journey Management Plan for all inter/ intra state commuting – crew change, supplies delivery, mobilization/de-mobilization. ▪ Maintain visible JTF presence within and around location as a deterrent to invasion or kidnapping.

13. LIST OF APPENDICES

Appendix 1 - HSE Critical Activities

Table of Authorization

HSSE Critical Activities (Rig-less Activities -Wells) Sign-Off:

Position	**Activity Number(s) Reviewed**	**Name**	**Ref Ind.**	**Signature**
Production Geosciences Discipline Principal	4a,24	Arochukwu, Elias	UPO/G/UVW	Elias Arochukwu Digitally signed by Elias Arochukwu Date: 2019.08.28 15:09:08 +01'00'
Petrophysics Discipline Principal	5b, 7a, 7b, 7c,7d,7e,17a, 18.	Laoye, Biodun	UPO/G/UVN	Laoye Abiodun Digitally signed by Laoye Abiodun Date: 2019.08.26 12:16:13 +01'00'
Reservoir Engineering Discipline Principal	5c	Okereke, Onyedikachi	UPO/G/UVC	Onyedikachi Okereke Digitally signed by Onyedikachi Okereke Date: 2019.08.24 09:46:53 +01'00'
Production Technology Discipline Principal	10, 11, 12, 13a, 13b, 14, 15,16, 17b	Komolafe, Gbenga	UPO/G/UDR	Gbenga Komolafe Digitally signed by Gbenga Komolafe Date: 2019.08.23 11:30:24 +01'00'
Well Intervention Lead, WRFM	26	Ricky Iyengumwena	PTW/O/NG	Ricky Iyengumwena Digitally signed by Ricky Iyengumwena Date: 2019.09.03 08:36:45 +01'00'

HSE Critical Task			Discipline	Close Out of HSSE Critical Task
Activity		Potential HSE Impact		
4a	Predict H2S presence. **DEP 25.80.10.18**	Loss of life and material integrity.	PT/PG*	The consequence of presence of H2S is loss of life and material integrity. However, available PVT data in Diebu Creek & nearby fields do not indicate H2S presence. The H2S prediction chart in Appendix 13, shows negligible H2S risk in the target Reservoir (E9500N). Also, focused evaluation of the reservoir using the SPDC souring potential chart highlighted that the souring tendency of the reservoir is minimal.
5b	Predict pore and fracture pressure in an undeveloped reservoir **DEP 25.80.10.10**	Loss of Well Control and Integrity	PP	Not Applicable. Target reservoir is developed.
5c	Predict pore and fracture pressure in an already developed reservoir **DEP 25.80.10.10**	Loss Well Control and Integrity.	RE	Pore pressure/fracture gradient prediction for developed reservoir has been done and endorsed by technical authority (ref. appendix 12).
7a	Plan logging – Wireline and LWD operations **DEP 25.80.10.15**	Well control, human exposure	PP	Not Applicable. No logging activity is planned during the STOG execution.
7b	Plan logging – radioactive sources **DEP 25.80.10.15**	Environmental impact, surface handling risks to people, loss of sources in the hole	PP	Not Applicable.
7c	Plan logging – explosives **DEP 25.80.10.15**	Potential for loss of life. HSSE management of surface and downhole operations	PP	• Personnel should follow the required guidelines on explosive tool handling as applicable. • The explosives should be kept secure in a dedicated location with perimeter protection and CAUTION sign, before and after operation. • Explosives should be handled by trained and certified personnel ONLY; Lead engineer is responsible for handling the tool during operations transfer.
7d	Plan logging - Pressurised formation fluid samples. **DEP 25.80.10.15**	surface handling: potential for loss of life.	PP	Not applicable.
7e	Plan logging - TZ and VSP survey operations **DEP 25.80.10.15**	Explosives, Airguns – Potential loss of life.	PP*/GP/WE	Not applicable.
10	Interpret cement bond integrity and casing wear log.	Zonal isolation and potential casing integrity.	PT*/PP	No cement bond log sighted. However, based on production history of this conduit, zonal isolation is not an issue and casing integrity is intact since no casing head pressures till date

11	Plan perforation and guns retrieval. **(Integrated as part of DEP 25.80.10.21)**	Hazards to life and facilities (misfired or unfired charges to surface).	PT*/WE	Radio silence will be observed while running in and running out of hole with the gun.
12	Predict sand production. **DEP 25.80.10.19**	Facility / flow-line integrity and loss of containment (LOC)	PT	Sand production is anticipated during well life and it is proposed to carry out Chemical sand consolidation to mitigate sand influx into wellbore.
13a	Predict produced fluid composition, especially contaminants like CO2, H2S, and mercury and potential formation water composition.	Corrosion and material integrity.	PT	No PVT samples taken directly from E9500N. However, PVT data from shallower reservoirs and well head gas analysis from NUNR-005 was used as analogue and it indicates no H2S is present. The souring tendency of the reservoir is also analysed to be minimal. Fluid sample analysis also show insignificant amount of CO2 in the reservoir as observed from applicable Diebu Creek PVT reports. Hence CO2 and H2S corrosion is highly unlikely.
13b	Predict and manage scaling + reservoir souring impact from water flooding /water injection	Corrosion and material integrity including hazard to life	PT	Not Applicable. Water flooding / water injection is not planned for the target reservoir.
14	Predict well-head and produced fluid temperature.	Well head growth, surface flowlines limitation and stress integrity.	PT	The predicted / expected wellhead fluid temperature of between 80 - 95degF falls within the range seen in Wells in the nearby fields and are not expected to pose a threat during this operation and indeed in the life of the well. Also, the surface casing is cemented in place and no wellhead movement have been seen when this well was producing
15	Plan (and execute) stimulation. **DEP 25.80.10.21**	Unsafe handling of chemicals (SHOC), equipment failure due to acid corrosion.	PT*/WE	Chemical treatment is planned in the scope of this intervention. Hence, SHOC card procedures are available for these chemicals. Appropriate PPE will be used by personnel on this job. Tool box talk and job hazard analysis will be conduction. Also, CWI have local experience handling these chemicals as these chemicals are deployed regularly in SPDC operation.
16	Establish safe operating boundaries (MAASP, closed in pressure, erosion and corrosion limits, etc.) for well integrity management.	Loss of well integrity.	PT	MAASP for the well and indeed well integrity boundary parameters are actively managed in e-WIMS. Presently, Diebu Creek 001L has action code 0 (May 2019) and no record of annulus pressure. Preventive maintenance/well integrity assurance activities are routinely carried out.
17a	Top-seal integrity assessment for primary recovery, waterflood, EOR and CO2 storage DEP 25.80.10.22	Human exposure, environmental and asset damage	PP	The risk of top-seal leakage due to primary recovery is considered low based on observations in the field and regional experience (Fields within the NUNR/ DBUC axis have produced for above 30 years with no recorded incidents).

				Geomechanical screening risk assessment carried out in Diebu Creek does not indicate risk of Top seal integrity issues.
17b	Prepare Abandonment Design option and program	Human exposure, environmental and asset damage.	PT	Not applicable.
18	Predict and monitor reservoir compaction and subsidence. DEP 25.80.10.16	Loss of wells, facility/platform integrity.	PP	The risk of compaction and subsidence is considered low based on the field and regional experience (Fields within the NUNR/ DBUC axis have produced for above 30 years with no recorded incidents). Geomechanical screening risk assessment carried out in Diebu Creek field does not indicate any risk of reservoir subsidence and compaction.
24	Prepare and maintain data to support emergency response. **DEP 25.80.10.12**	Lack of data or wrong data during emergency response may aggravate the emergency.	PT/PG*	All relevant well data and latest well information required for emergency response have been loaded in the SIRUS CATALOG and Sharepoint (see links below): SIRUS CATALOG Share point
26	Identify Hazards (HAZID) and prepare Hazard Register	Integral part of HSSE Case development. To confirm selected concept/process can be developed into a safe and operable plant.	WE	This intervention is planned on existing well. Hence, well design is not applicable. HSSE risks and mitigation for this Intervention will be built into the execution program

*Accountable Discipline, as per Published DEP

Appendix 2: Diebu Creek 001L Well Status Diagram (Current Status)

INITIAL COMPLETION STATUS AS AT 21/07/73

WELL : DIEBU CREEK - 01

CASING

SIZE	GRADE	WT.	DEPTH	CEMENT	SG
9-5/8	P110	47	1010		
"	N-80	47	8389		
"	P110	47	10901		
7"	N80	32	12661		

WELLHEAD

ITEM	TYPE	SIZE(INS)	WP (PSI)
GATE VALVE			
XMAS	DSB	10" x 3-1/8" x 3-1/8"	5000
ADAPTOR FLANGE			
TUBING HANGER	DCB	10" x 3-1/2 ASL x 3-1/2 ASL	5000 x 3000
TUBING H. SPOOL	DCB	12" x 10"	
RISER SPOOL			
CSG. H. HOUSING	WF	12" x 13-3/8	3000
CSG. H. SPOOL	WF		
SEAL BUSHING	'X	12" x 9-5/8	ENERGISED

TUBING

STRING	SIZE	WT	GRADE	TYPE
LS	3-1/2	9.3	N80	HC-ASB
LS	3-1/2	9.3	N80	ASL
SS	3-1/2	9.3	NS	HC-ASB
SS	3-1/2	9.3	NS	ASB

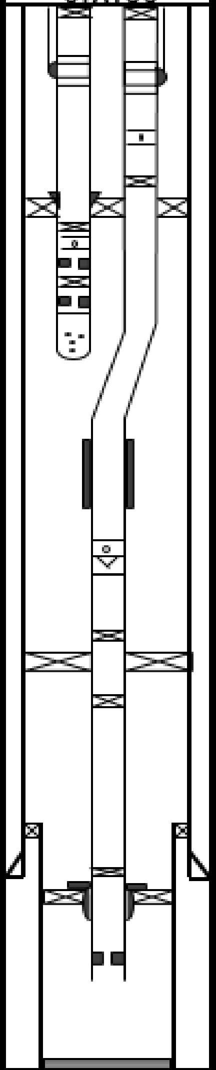
DEVIATION

MAX	° AT	FT
DFE		50.6 FT
DFE TOP CHH		37 FT
TOP FLANGE XTREE		30.3 FT

HOLE	OPEN HOLE PLUGS	ACTIVITY	MAX SG	RESERVOIR	DATE

SAND	PERFORATIONS
E1.0	10306 - 10312 FT AH SCON
E9.5	11855 - 11860 FT AH TTSCON 10/12/73

STATUS

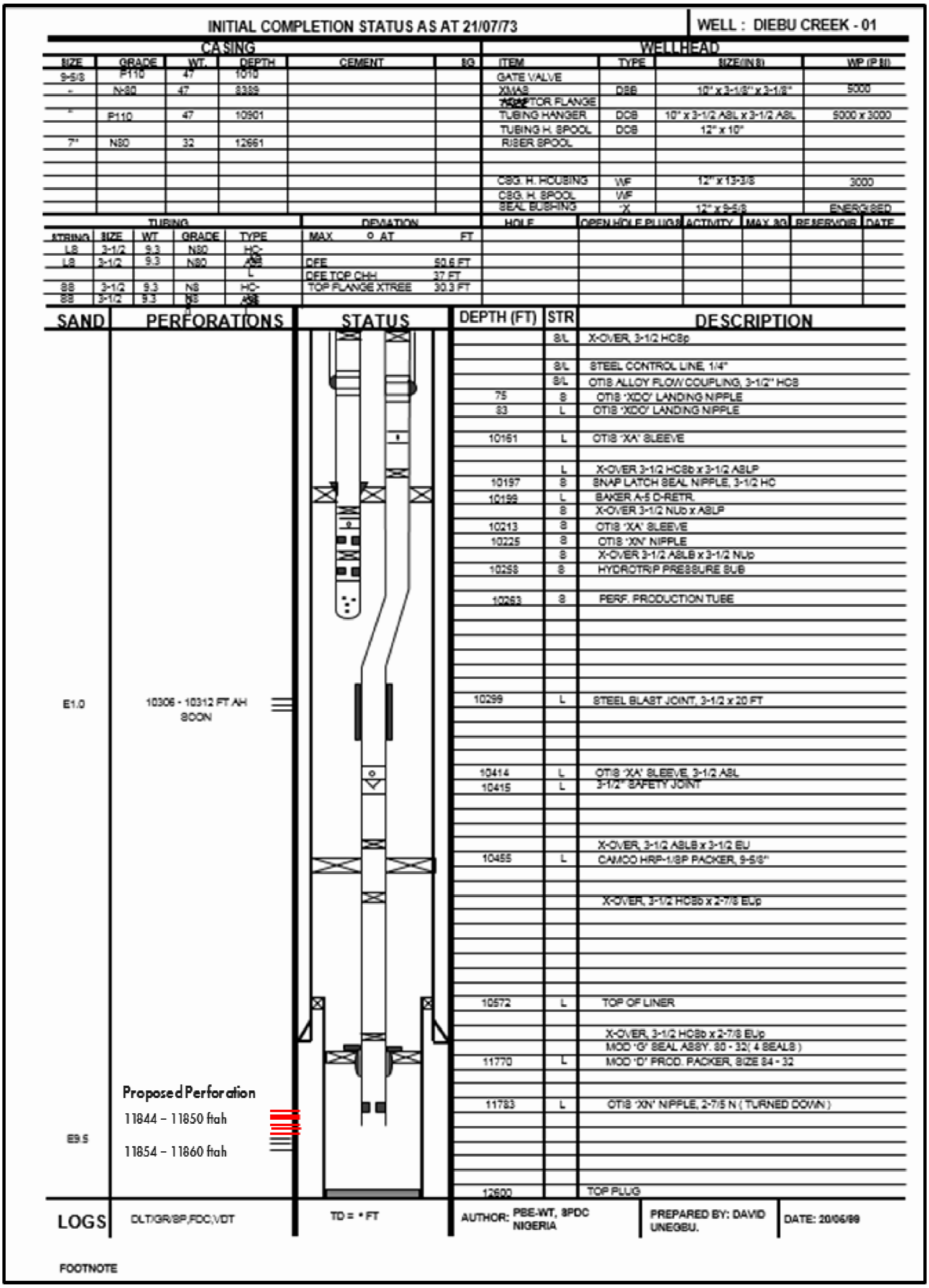


DEPTH (FT)	STR	DESCRIPTION
	S/L	X-OVER, 3-1/2 HCSp
	S/L	STEEL CONTROL LINE, 1/4"
	S/L	OTIS ALLOY FLOW COUPLING, 3-1/2" HCS
75	S	OTIS 'XDO' LANDING NIPPLE
83	L	OTIS 'XDO' LANDING NIPPLE
10151	L	OTIS 'XA' SLEEVE
	L	X-OVER 3-1/2 HCSb x 3-1/2 ASLP
10197	S	SNAP LATCH SEAL NIPPLE, 3-1/2 HC
10199	L	BAKER A-5 D-RETR.
	S	X-OVER 3-1/2 NUb x ASLP
10213	S	OTIS 'XA' SLEEVE
10225	S	OTIS 'XN' NIPPLE
	S	X-OVER 3-1/2 ASLB x 3-1/2 NUp
10258	S	HYDROTRIP PRESSURE SUB
10263	S	PERF. PRODUCTION TUBE
10299	L	STEEL BLAST JOINT, 3-1/2 x 20 FT
10414	L	OTIS 'XA' SLEEVE, 3-1/2 ASL
10415	L	3-1/2" SAFETY JOINT
		X-OVER, 3-1/2 ASLB x 3-1/2 EU
10455	L	CAMCO HRP-1/SP PACKER, 9-5/8"
		X-OVER, 3-1/2 HCSb x 2-7/8 EUp
10572	L	TOP OF LINER
		X-OVER, 3-1/2 HCSb x 2-7/8 EUp
		MOD 'G' SEAL ASSY. 80 - 32(4 SEALS)
11770	L	MOD 'D' PROD. PACKER, SIZE 84 - 32
11783	L	OTIS 'XN' NIPPLE, 2-7/5 N (TURNED DOWN)
12600		TOP PLUG

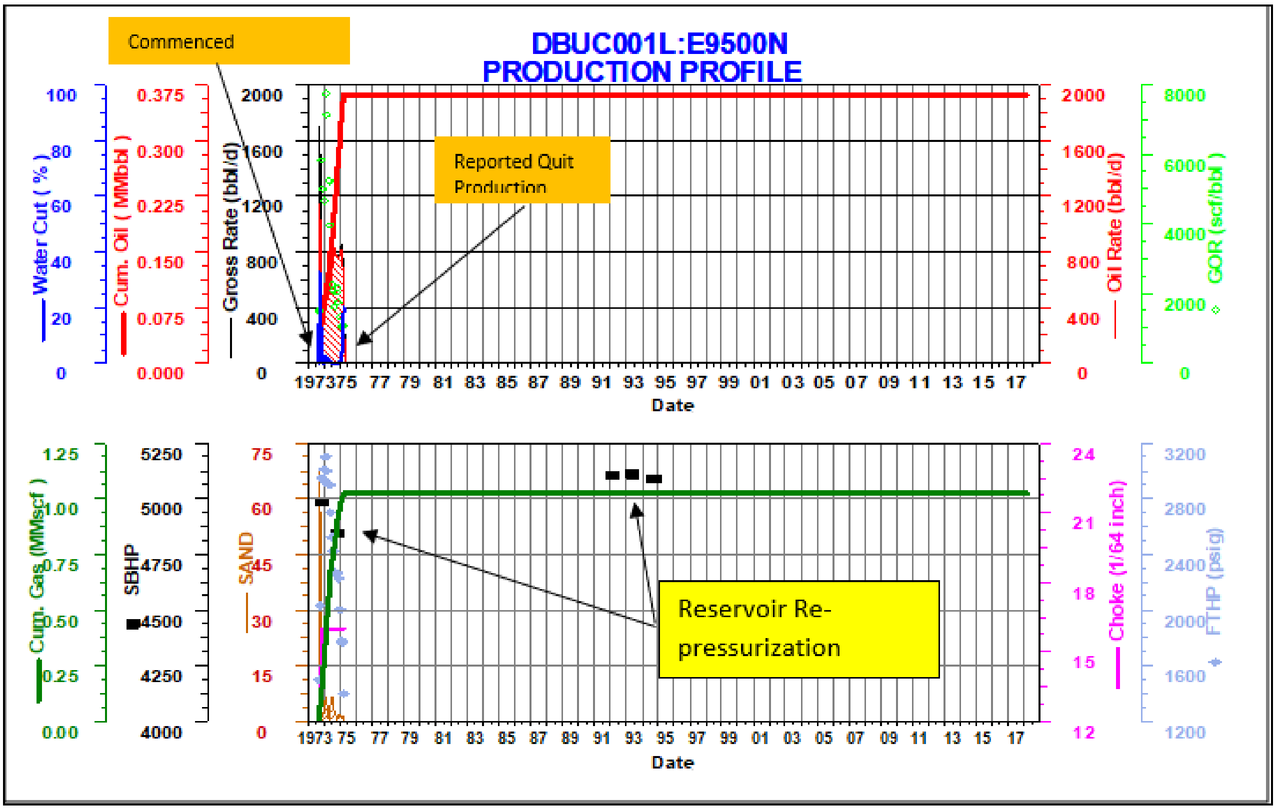
LOGS	DLT/GR/SP,FDC,VDT	TD = * FT	AUTHOR: PBE-WT, SPDC NIGERIA	PREPARED BY: DAVID UNEGBU.	DATE: 20/06/08

FOOTNOTE

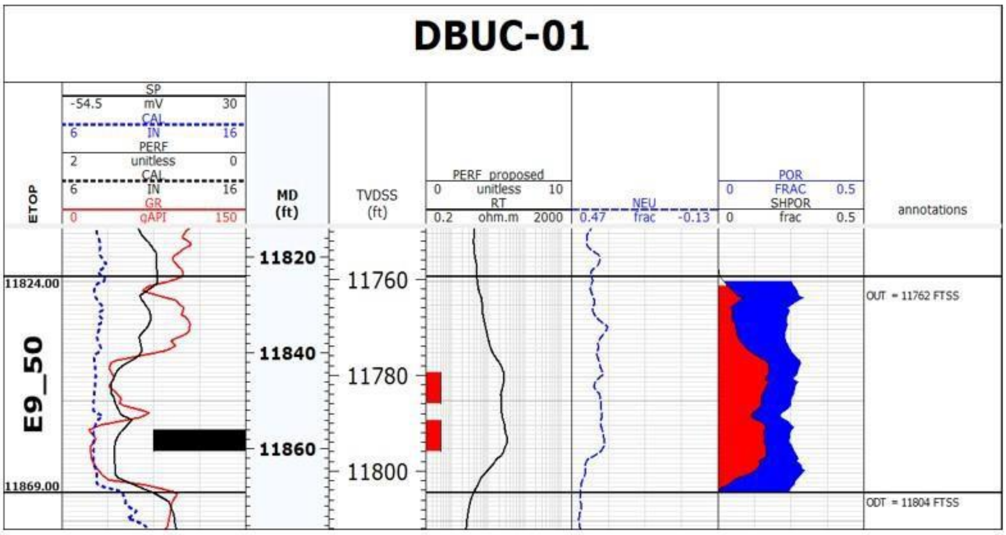
Appendix 3: Diebu Creek 001L Well Status Diagram (Proposed Status)



Appendix 4: Diebu Creek 001L Well Performance Plot



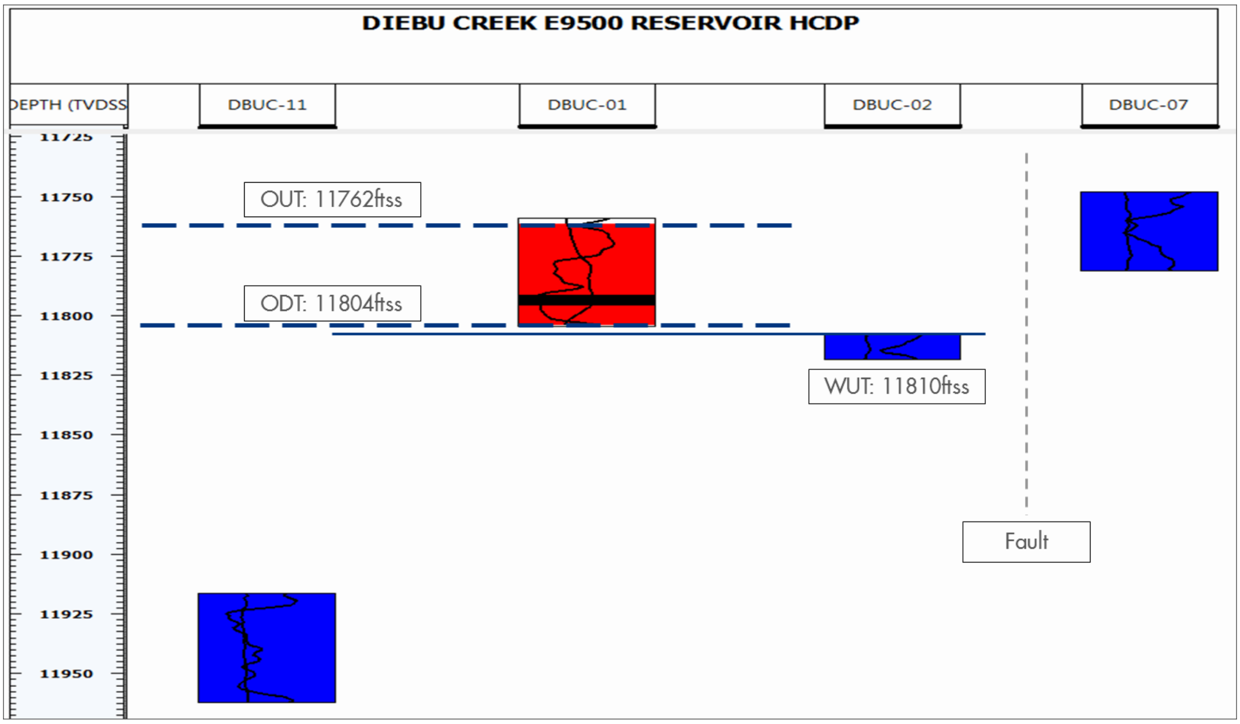
Appendix 5: Diebu Creek 001 Petrophysical Data Layout



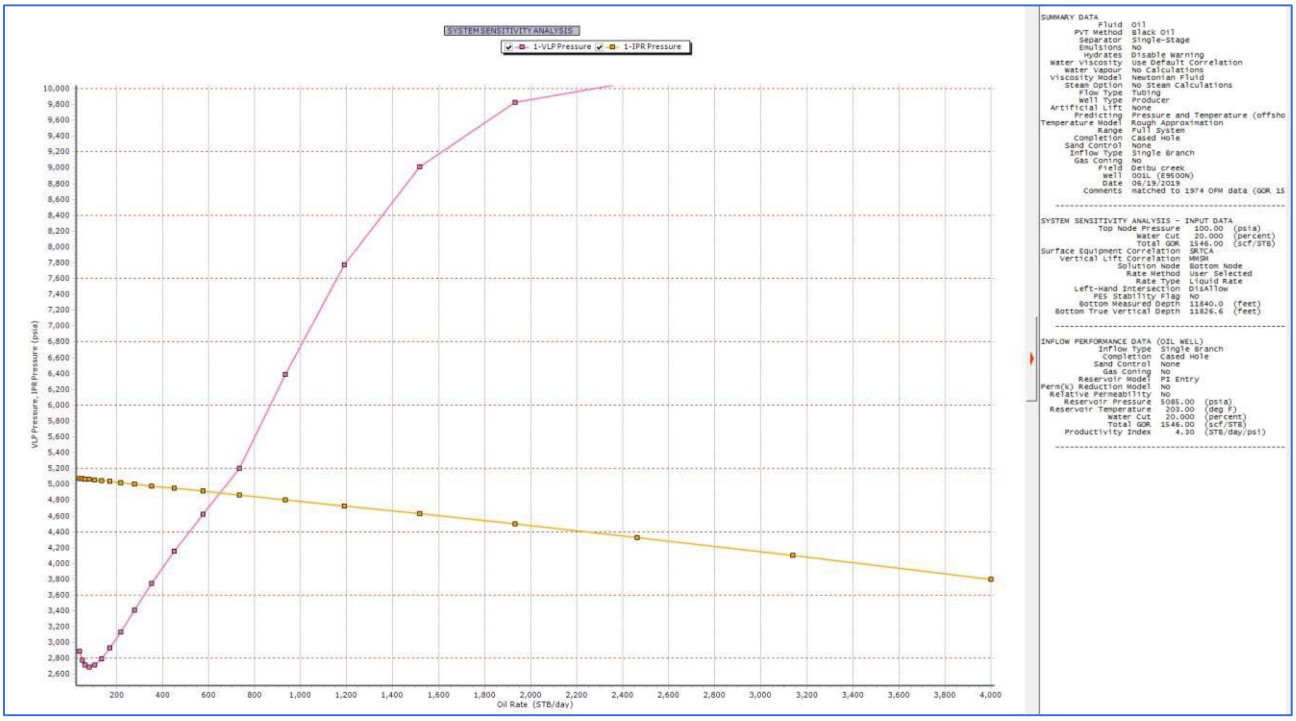
Existing Perforation (11856ftah – 11860ftah)

Proposed Perforation (11844ftah – 11850ftah ; 11854ftah – 11860ftah)

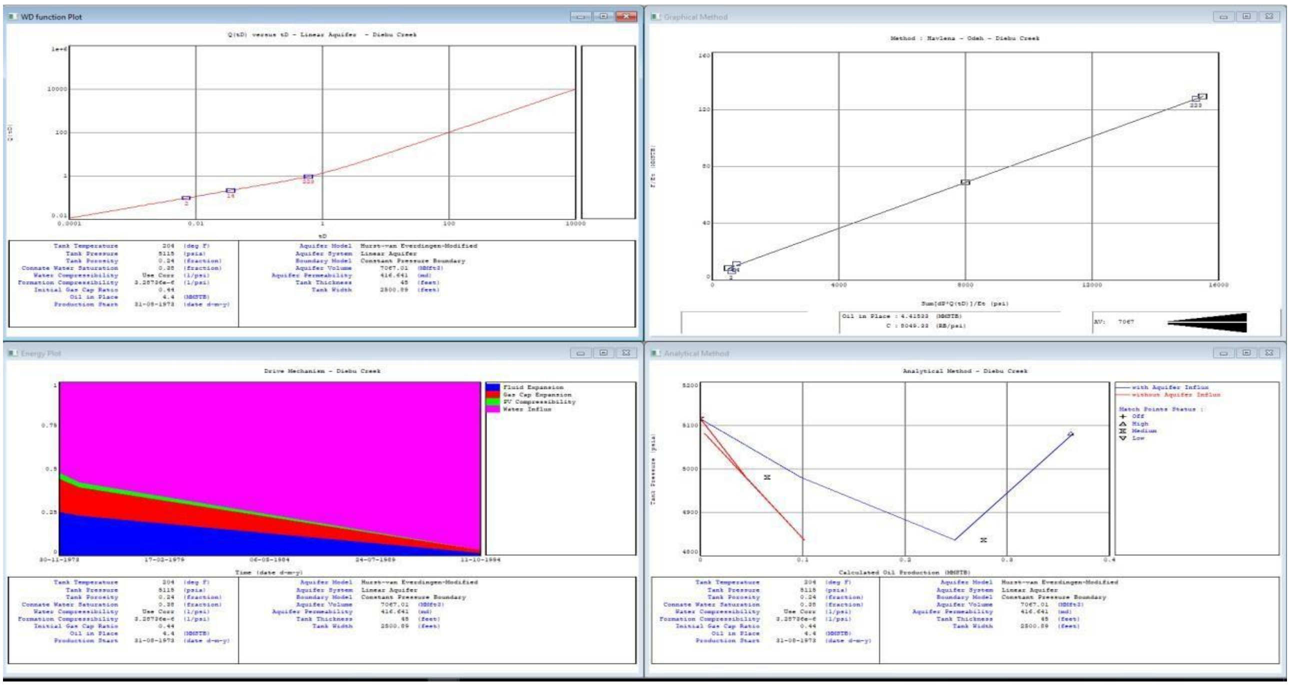
Appendix 6: Diebu Creek E9500N Hydrocarbon Distribution Plot

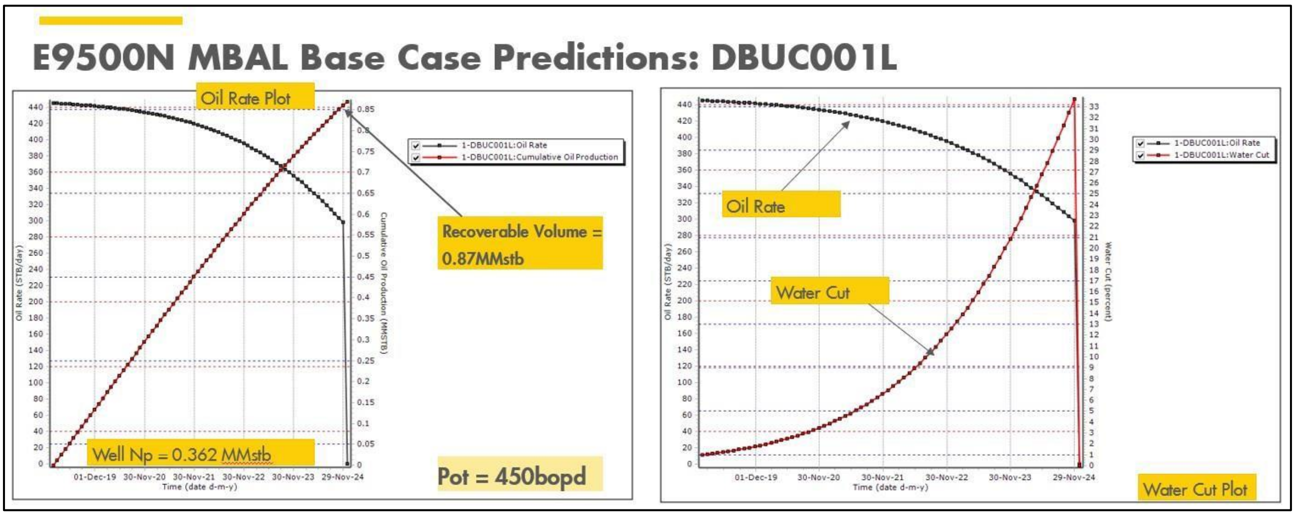


Appendix 7: Diebu Creek 001L Inflow/outflow Plot

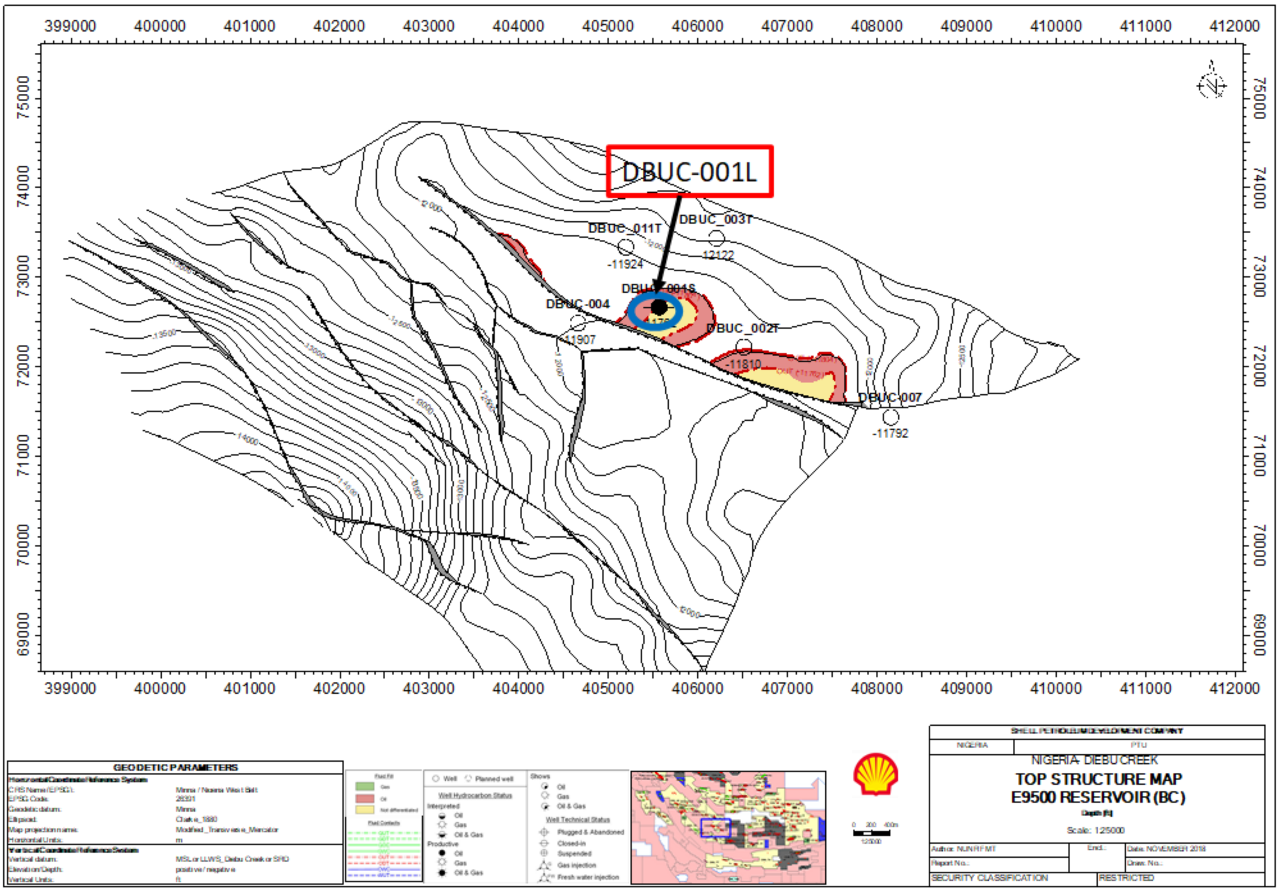


Appendix 8: Diebu Creek 001L Well forecast plots

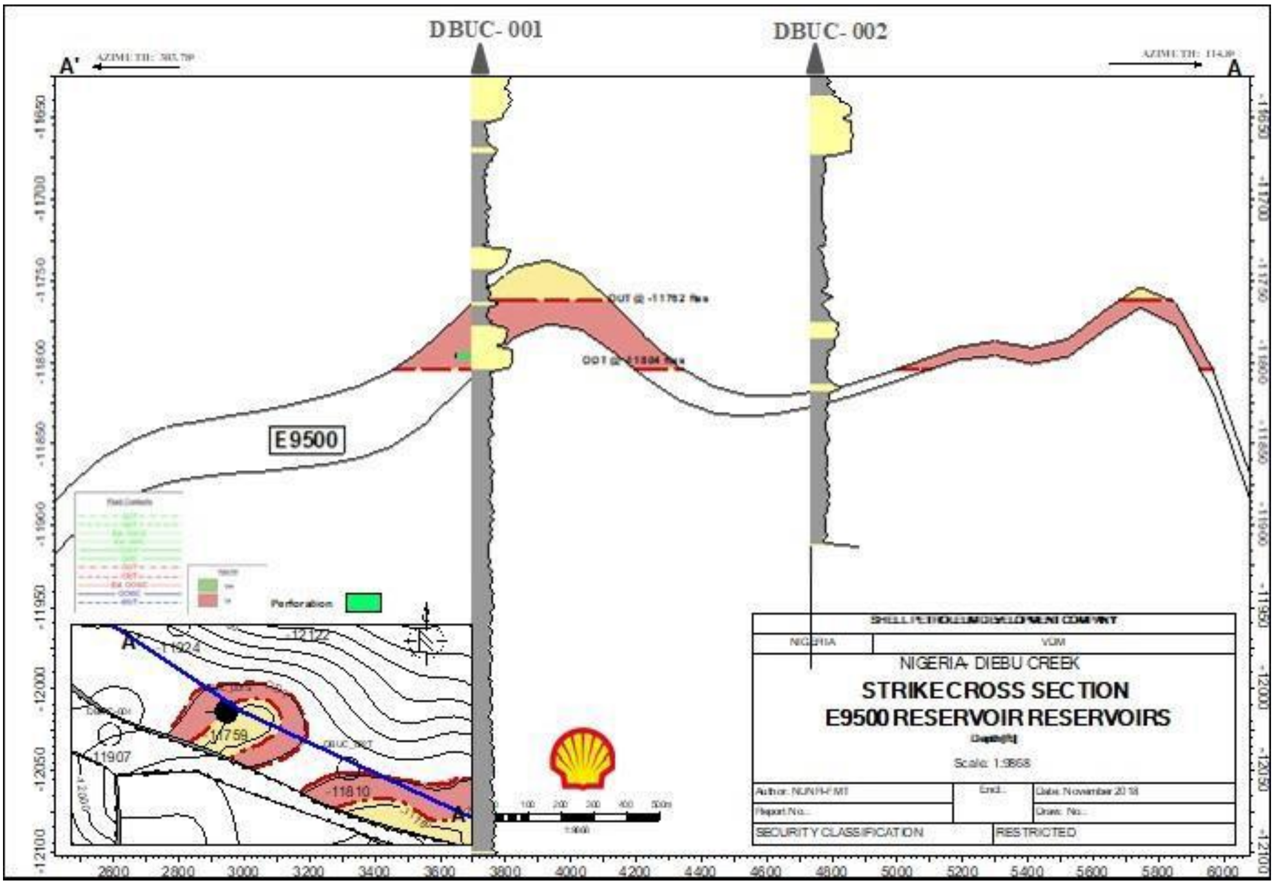




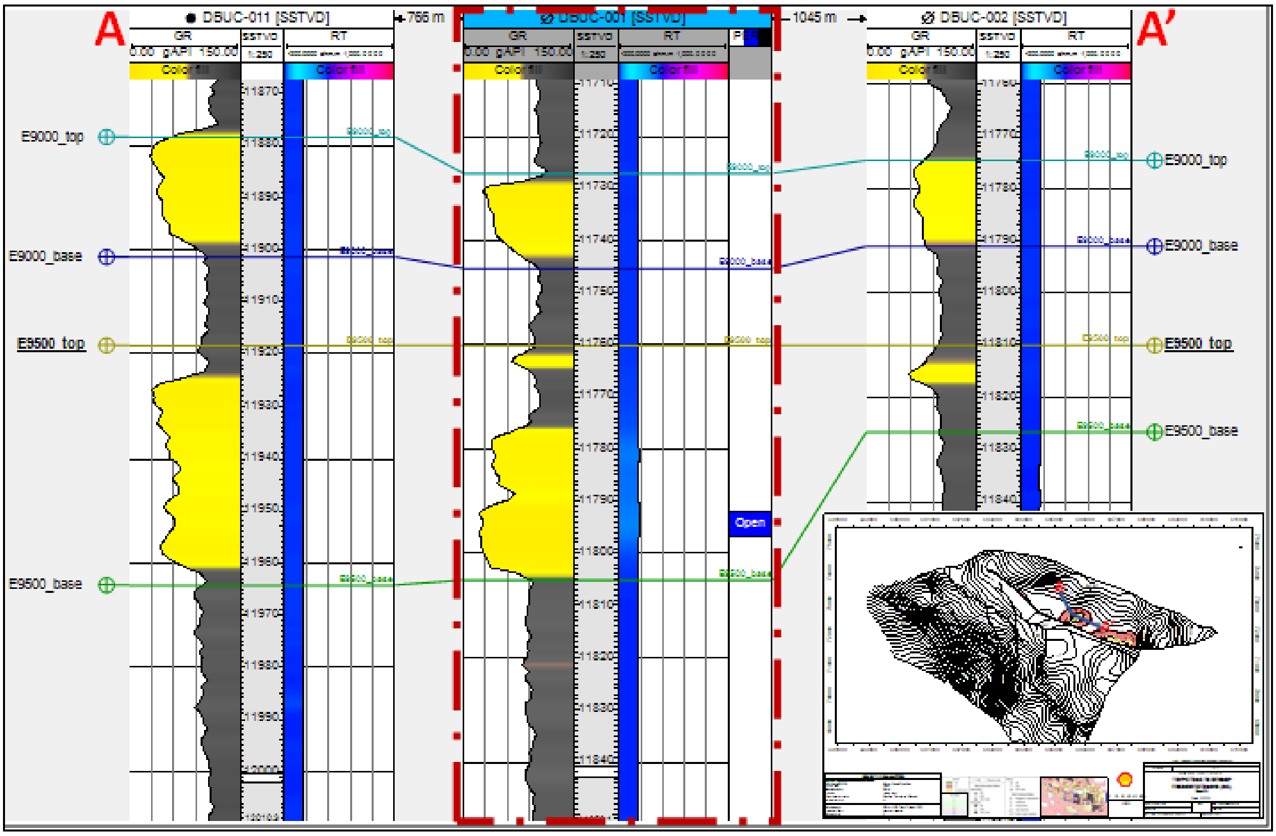
Appendix 9: Diebu Creek E9500N Top Structure Map



Appendix 10: Geological Cross Section through E9500N Reservoir



Appendix 11: Correlation Panel through E9500 Reservoir



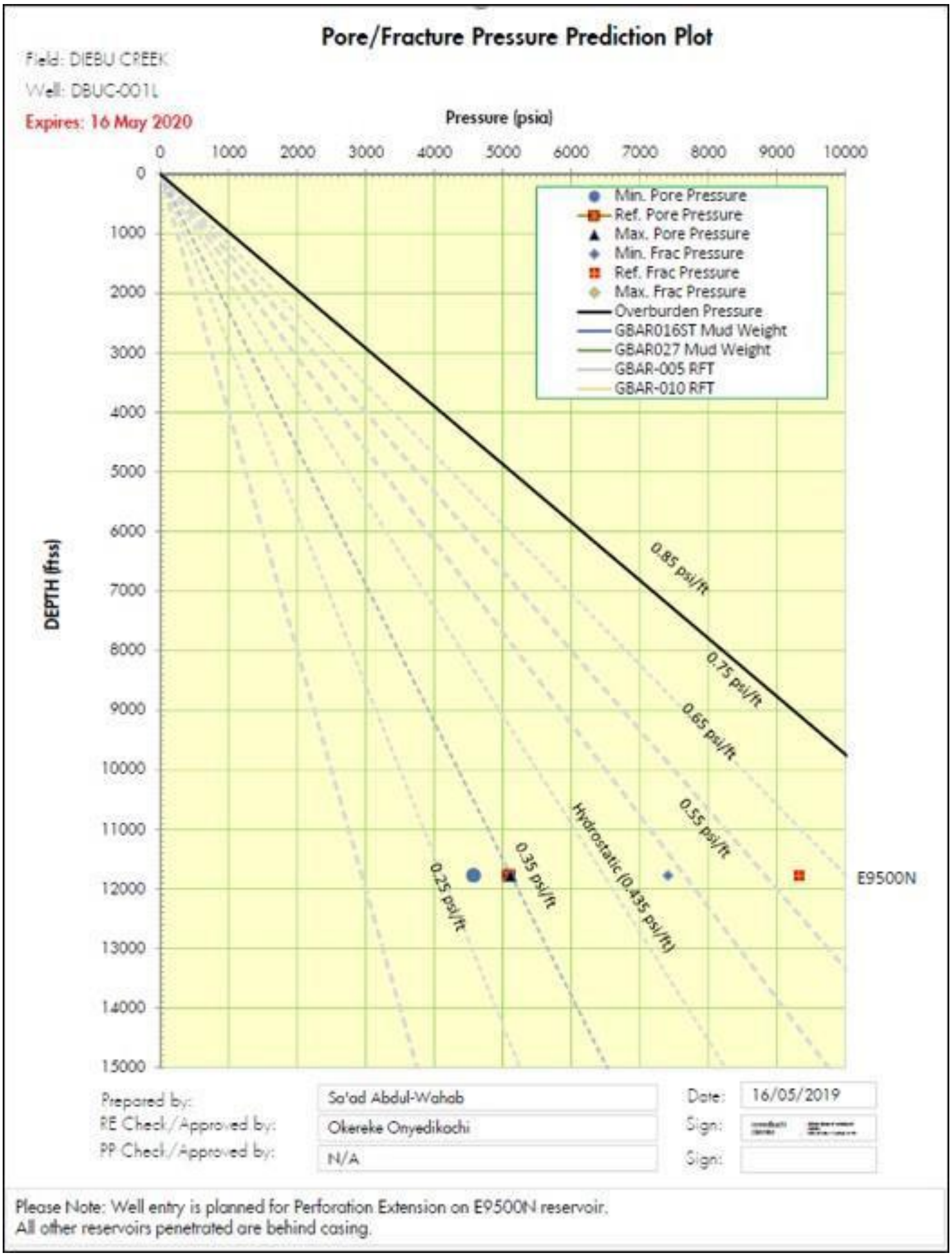
Appendix 12: Pore Pressure Prediction for Diebu Creek 001L on E9500N

FIELD:	Diebu Creek
WELL NAME:	DBUC-001
PLATFORM/RIG:	Rigless
PREPARED BY / CHECKED BY:	Sa'ad Abdul-Wahab/ Okereke Onyedikachi
ISSUED DATE :	16 May 2019
REVISION NO:	v1.0
RE ENTRY DATE:	20 November 2019
EXPIRY DATE:	15 May 2020

Pore Pressure Prediction at Top Reservoir for well DBUC-001

Formation	TV-Depth of Pressure Prediction and Reference Depth	Fluid Type Prognosis at Top of Sand along Well Trajectory	Is Reservoir Developed?	Formation Pore Presure Prediction at Top of Proposed Perforation along Well Trajectory					Pore Pressure Gradient Prediction at Top of Proposed Perforation along Well Trajectory					Fracture Gradient Prediction at Top of Proposed Perforation along Well Trajectory					Remarks
				Minimum (psia)	Reasonable Low (psia)	Reference Case (psia)	Reasonable High (psia)	Maximum (psia)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	
E9500N	11775	Oil	Yes	4574	4834	5080	5103	5114	0.388	0.411	0.431	0.433	0.434	0.630	0.709	0.792	0.865	0.917	Formation pore pressure estimated at the top of proposed perforation. Reservoir witnessed ca. 1% pressure depletion.

Prepared By :	Sa'ad Abdul-Wahab Name	SPDC-UPO/G/UVC Team Indicator	16 May 2019 Date
RE Check/Approved By :	Okereke Onyedikachi Name	Onyedikachi Okereke Signature	
PP Check/Approved By:	N/A Name	Signature	
Validity :	Predictions valid till 15 May 2020 (Note : PP/FP must be re-validated prior to spud/well re-entry)		


Pore/Fracture Pressure Prediction Plot
Field: DIEBU CREEK
Well: DBUC-001L
Expires: 16 May 2020
Pressure (psia)
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
DEPTH (ftss)
11000
12000
13000
14000
15000
Min. Pore Pressure
Ref. Pore Pressure
Max. Pore Pressure
Min. Frac Pressure
Ref. Frac Pressure
Max. Frac Pressure
Overburden Pressure
GBAR016ST Mud Weight
GBAR027 Mud Weight
GBAR-005 RFT
GBAR-010 RFT
0.85 psi/ft
0.75 psi/ft
0.65 psi/ft
0.55 psi/ft
Hydrostatic (0.435 psi/ft)
0.35 psi/ft
0.25 psi/ft
E9500N
Prepared by:
RE Check/Approved by:
PP Check/Approved by:
Sa'ad Abdul-Wahab
Okereke Onyedikachi
N/A
Date:
16/05/2019
Sign:
Sign:
Please Note: Well entry is planned for Perforation Extension on E9500N reservoir.
All other reservoirs penetrated are behind casing.

Appendix 13: H2S Prediction for Diebu Creek 001L on E9500N Reservoir

DIEBU CREEK 001L H_2S PREDICTION FOR E9500N RESERVOIR

- Diebu Creek 001 is completed as a TSD oil producer on the E1000X & E9500N sands. Diebu Creek-001L is proposed for a thru-Tubing perforation extension activity on the E9500N reservoir.

PVT Report and Production History

- There is no PVT Report for the E9500N reservoir but there is for the E1000X & E2000 reservoirs. The PVT report does not confirm the presence or absence of H2S in the E1000X reservoir, however it confirms the absence of H2S in the E2000 reservoir.
- There is no documentation of H2S produced from E9500N reservoir while on production.
- Gas samples from Diebu Creek separators obtained in 2002 indicates absence of H2S.
- Well head gas samples from the adjoining Nun River field about16.5km to the north, obtained in December 2018 from NUNR-005 on NUNR G4000 reservoir indicates absence of H2S. NUNR-005 encounters G4000 at 12415ftss whereas DBUC-001 encounters E9500N at 11759ftss. With the structural depth difference between the two reservoirs at 656 ft (<1000 ft), Nun River G4000 is a suitable analogue for Diebu Creek E9500N.
- See snapshot of PVT reports and gas sample analysis on the next slides.

Souring Potential

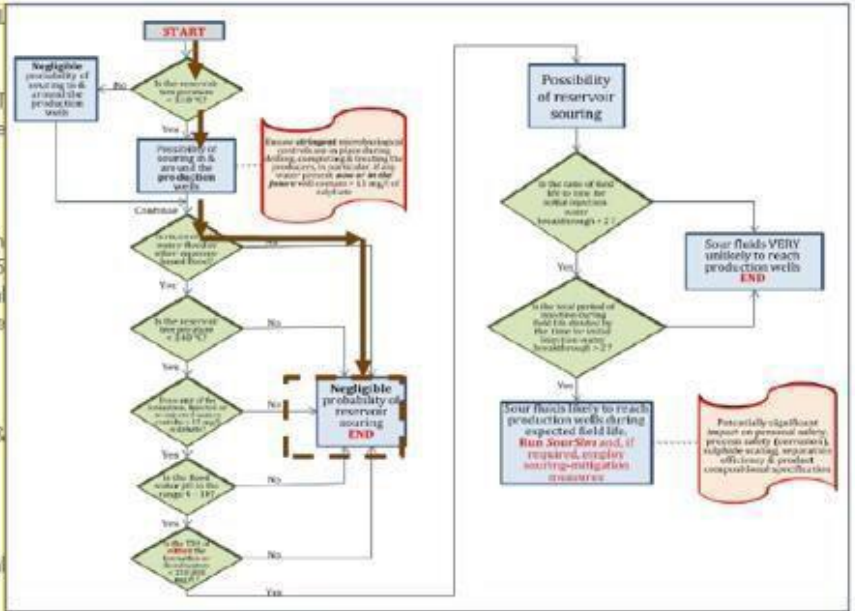
- The consequence of H_2S is loss of life and material integrity. However, available PVT data in Nun River & nearby fields do not indicate H_2S presence.
  - The maximum reservoir temperature for the target sand (E9500N) is 95.5 °C (below 110 °C)
  - No water injection in Diebu Creek & nearby fields that can lead to reservoir souring.
  - No secondary or Tertiary recovery processes are being practiced in the field.
- Also, due to these reasons the souring tendency of the reservoirs is minimal (refer to the souring potential chart in attachment1);
- The fresh-saline water interface in DBUC 001 is 4852 ftss, which is about 5191 ftss & 6907 ftss away from the E1000X and E9500N reservoir. The possibility of fresh water migration into this reservoir (E9500N) is low.

External Risks

- There is a risk of the Equipment (e.g. CT, Tanks) to be used in this operation, introducing some H_2S based on residue from their previous operations reacting with the acid to be used now.

Mitigations

- Check and Confirm that previous use of the equipment would not intentionally give rise to H_2S after contacting HCL
- H_2S Gas monitors is mandatory during Well Intervention execution to alert the crew of any latent threats.
- Appropriate PPE's including self contained breathing respirator must be worn as mitigation.



Prepared by	Unukogbon Obaro (PG)	Nwosu Obiora (PT)	30/ April / 2019
Checked by	Ahmed Suleiman (PG TA2)	Suleiman Ahmed Digitally signed by Suleiman Ahmed Date: 2019.05.06 08:30:14 +01'00'	
Approved by	Biambo Tamunotonye (PT TA2)	Tammy Biambo Digitally signed by Tammy Biambo Date: 2019.05.07 09:02:26 +01'00'	
Approved by	Arochukwu Elias (PG TA2)	Elias Arochukwu Digitally signed by Elias Arochukwu Date: 2019.05.06 10:45:59 +01'00'	

RESTRICTED April 2019 2