THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOLO CREEK 043 WELL CLEAN-UP/TEST PROPOSAL

February 2017

Well No	KOLO CREEK 043
Reservoir	F2000X

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1.0 BACKGROUND

Kolo Creek 043 is a gas development well that was drilled to provide a drainage point on the F2000X reservoir. The reservoir gas recoverable volume is 945.4 Bscf and KOCR043T will develop 468.9 Bscf with an initial gas production potential of 70 MMscf/d. The well was spudded on the 7th August 2013, drilled to a TD of 14,350 ftah (13,601 ftss), and completion operation ended on 25th January 2015. The well penetrated the F2000X sand at 13381 ftss as prognosticated in the sidetrack and encountered a gross gas column of 220 ft-tvt.

The well was drilled and completed as a Single String Single (SSS) gas producer on the F2000X gas reservoir with 7" 13Cr / VM110 HCSS tubing equipped with Tubing Retrievable Surface Controlled Subsurface Safety Valve (TRSCSSSV). Reslink standalone screen was installed across the sand face for effective sand control. Kolo Creek 043 was suspended with FIV shifted closed and 0.48 psi/ft NaCl brine in the tubing and 6" monolock plug set at 60 ftah. The fluid in the drainhole is POBM.

Two other wells: Kolo Creek 045 and Kolo Creek 046 are completed on the reservoir. However, no production has been recorded from the reservoir. The F2000 is an overpressured reservoir with expected pressure of 9430 psia. Well testing spread and procedure will therefore be designed to manage expected high surface pressures.

It is proposed to clean up the well to about 50 MMscf/d to remove drilling and completion debris and fluids and then conduct Multirate test to ca. 50 MMscf/d on the F2000 interval. This is due to environmental considerations. Results from the MRT will be used to calibrate the well deliverability and advise well operating envelope.

1.1 Clean-Up/Test Objectives

The objectives of the well clean-up and test are as follows:

- Clean up the well to remove drilling mud, mud filter cake, completion fluids and debris.
- Conduct multirate test to a maximum of 50 MMscf/d to determine well deliverability.
- Conduct Build up test to obtain data required for reservoir characterization.
- Conduct Static Gradient Survey to obtain static datum pressure and temperature data.
- Acquire surface production data to facilitate further evaluation of well performance.

1.2 Justification

The well's objective is to provide gas to the Soku gas plant as part of the wells delivering gas to NLNG. The cleanup is required to get rid of any remaining fluid and debris (cuttings, dope, weighting agent etc.) resulting from both drilling and completion operations, which might lead to impairment, thus, resulting to a compromise of the well's potential and expected recovery.

1.3 Work Summary

The high level summary of the clean-up/well test work scope is given as follows:

- Pump treatment fluid and carry out well lift.
- Clean-up F2000X interval
- Carry out MRT on F2000X interval
- Carry out build-up and carry out SG survey

2.0 WELL CLEAN-UP DESIGN

During the clean-up operation, a specially formulated oil mud breaker solvent system will be pumped to displace the pseudo oil based mud in the open hole. This will be jetted across the Reslink standalone screen in a minimum of 3 passes. The well should be flowed long enough (ref Table 1 below) to allow sufficient time to offload well on each bean while monitoring sand production. After every bean change, sand trap will be purged for inspection of well effluents.

If there is significant sand production (>0.5 lbs/MMscf), refer to Appendix 3D for contingency plan for excessive sand production.

All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

Maximum Clean-up rate, constrained to 50 MMscf/d due to environmental considerations (Noise, vibration and flare intensity) is expected to create enough turbulence to lift all completion fluids and debris from the well. However, if there is need to clean up at higher rates, this will be done as a separate operation when the well is hooked up to the facility.

2.1 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
- Downhole Shut in tool
- Clamp on sand monitor
- Pressure let-down choke
- Liquid knock out vessel
- Surface Tanks - to receive initial well effluent; completion and kill brine, mud etc.)
- Coiled Tubing/Nitrogen
- Slick line
- Flare head burner
- Mono- Ethyl Glycol (To mitigate hydrates at low rates)
  * Note: Expected surface pressures in the range of 6900 – 7200 psi. All equipment upstream of choke manifold to be rated for 10,000 psi maximum pressure.

2.2 Well Clean-Up Operation

The well cleanup operation will commence with the opening of the FIV and unloading operation using coiled tubing. The clean-up will then commence from choke 28/64th (Note bean should be gradually increased). Clean-up parameters are not accurately predictable, however,

Table 1 provides a fair guide. Appendix 2a & b are snapshots from PROSPER showing a graphical display of the wellbore model results. The flow rates, WGR, sand production and FTHP will be measured and recorded to ensure adequate well clean-up until a stabilized FTHP and expected minimum WGR ca. 0.7 bbl/MMscf is achieved (i.e. completion fluid fully evacuated). Thereafter, the well will be shut-in for a minimum of 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

The flow back well effluent (completion brine and mud) will be evacuated with vacuum truck to the Gbaran Central Processing Facility (CPF) for disposal.

2.3 Clean-up Work Summary

The summary of the clean-up work scope is given as follows:

- Check wellhead pressures – CITHP and CHP (A & B Annulus)
- Retrieve monolock plug at 60ft
- RIH CT to open the FIV, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Pump nitrogen (if required) to lift until well is confirmed to sustain natural flow
- Clean-up well as per program (Table-1), ensuring stable flow on each advised bean
- Shut-in well for a minimum of 24 hours for initial reservoir stabilization

NOTE:

- Initial opening of well must be during daylight.

- Bean-up must be done gradually to achieve good bridging behind standalone screen.
- Bean-up should be carried out when flow stabilizes. At each stage, record bean size, gas flow rate, FTHP, FTHT, CGR, WGR, and sand rate.
- Bleed down A & B annulus when pressure exceeds 1000 psi for A annulus and 400 psi for B annulus. Record volume of fluids recovered from A & B annulus during all operations. (See Appendix 10 for expected incremental AFE pressures)
- Flow well until well is properly cleaned, not exceeding a maximum gas rate of 50 MMscf/d. Well is properly cleaned-up when clean up criteria is achieved as specified in Table 1 below.
- All temporary pipe connections must be properly secured and tested to expected pressures

Table 1: KOLO CREEK 043 Well Clean-up Guide

Estimated Rate (MMscf/d)	Expected Bean Size (1/64th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
20	24	0.7	7210	4	5	Take sample, check for sand, measure FTHP.
30	30	0.7	7139	4	7	Take sample, check for sand, measure FTHP.
40	34	0.7	7074	4	9	Take sample, check for sand, measure FTHP.
50	40	0.7	6993	5*	13	Take sample, check for sand, measure FTHP.

Stable flow should be achieved on each bean before moving to the next advised bean

*** Clean up criteria**

Stabilized THP for at least 1 hour, no mud returns, BSW of liquid sample < 5%

Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 50 psia

3.0 MULTI-RATE TEST AND FLOWING/BUILD-UP/SG SURVEY

Summary of MRT workscope is given below

- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,010 ftah).
- Open up well and conduct Multirate test as per program (Table 2)
- Shut in well for 48-hour final build-up test with DHSIT in closed position.
- Carry out SG survey.
- Secure well.
- Rig down equipment.

3.1 Initial Build-up Period

- Close in well at choke manifold for 24 hours for an initial build-up/stabilization after well clean-up to allow for reservoir stabilization prior to multirate test. Record CITHP.
- RIH Slickline and install pressure/temperature memory gauge and Down Hole Shut-In Tool (DHSIT) at “RPT – Nipple” (ca.11,010 ftah).
- Monitor CITHP for pressure stabilization before proceeding to MRT.

3.2 Flowing Period

- Open up well and carry out multi-rate test; starting at a rate of 20 MMscf/d, gradually bean up to a maximum rate of 50 MMscf/d. See Table 2 below for guide on production parameters during the flow period.

Table 2 MRT data

Estimated Rate (MMscf/d)	Expected Bean Size (fixed choke) ($1/64^{th}$)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period* (hr)	Expected Drawdown (psi)	Comments
20	24	0.7	7210	4	5	Take sample, check for sand, measure FTHP.
30	30	0.7	7139	4	7	Take sample, check for sand, measure FTHP.
40	34	0.7	7074	4	9	Take sample, check for sand, measure FTHP.
50	40	0.7	6993	4	13	Take sample, check for sand, measure FTHP.
0	0	0	-	48	0	48hr shut in period

- At each choke, collect and analyze sample every 15 minutes, record gas flow rate, FTHP, FTHT, CGR, WGR, and sand rate.
- After the last flow period, shut in well for 48 hours (Final Buildup duration determined from section 4.0) and subsequently commence Static Gradient Survey (See Table 3 below).
- All the other wells completed in the F2000X reservoir must be shut-in during the build-up of KOCR043T, this is to avoid interference from these wells.

3.3 Final Build-up and Static Survey Period

- Confirm well has been closed in for 48 hours build-up.
- Carry out static gradient (SG) survey while POOH wireline memory gauge and DHSIT at the depths as detailed in Table 3.
- Duration of survey at each stop should be ca. 10mins.
- POOH with gauges and R/D S/line.
- Download wireline memory gauge.
- Close TRSCSSSV and line up well to production.
- Handover well to production.

Table 3: Static Gradient Survey Stops.

Depth Tag (d)	Depth (d)	Intervals	Duration at depth	Comment/Basis for Stops Selection
	ftah from DFE [DFE Elevation = 58 ft]	Ft	Minutes	
Deepest Survey Depth	11,010	-	0	Deepest Survey depth. R nipple Depth
1st Stop	10,990	20	10	1st Set of Stops: 3 Stops at 20ft intervals closest to deepest survey point enable accurate regression/ extrapolation to reservoir pressure.
2nd Stop	10,970	20	10	
3rd Stop	10,950	20	10	
4th Stop	10,850	100	10	2nd Set of Stops: 3 Stops at 100ft intervals to ensure accurate estimate of well fluid gradient
5th Stop	10,750	100	10	
6th Stop	10,650	100	10	
7th Stop	10,150	500	10	3rd Set of Stops: 3 Stops at 500ft intervals to ensure accurate estimate of well fluid gradient
8th Stop	9,650	500	10	
9th Stop	9,150	500	10	
10th Stop	8,150	1000	10	4th Set of Stops: 3 Stops at 1000ft intervals to ensure accurate estimate of well fluid gradient
11th Stop	7,150	1000	10	
12th Stop	6,150	1000	10	
13th Stop	4,150	2000	10	5th Set of Stops: 3 Stops at 2000ft intervals to ensure accurate estimate of well fluid gradient
14th Stop	2,150	2000	10	
15th Stop	150	2000	10	

4.0 SAPHIR TEST DESIGN

The focus of the test design is to determine the duration of the flow and optimal build up time, such that there is appreciable amount of data to enable the determination of reservoir properties (Permeability-height product-kh, skin, etc) and possible existence and nature of any boundary(ies)/discontinuity(ies) (fault/Baffles/GWC).

Kappa's Ecrin Saphir Software was used in this design. The model was built based on the well and reservoir data as detailed in Table 4. Pressure simulations were generated based on the rates in Table 2. The generated pressure responses were subsequently analyzed using derivative plots to determine the time taken for the pressure perturbations to be felt at the possible boundaries and also achieve stabilization of about 0.01 psi/hr (as seen in SAPHIR). Various scenarios (sensitivities) were built to test what the pressure response would be given the uncertainties in permeability, and skin. These sensitivities were collectively analyzed, and the optimal test time selected.

4.1 Input Data

The test design input data are as detailed in the table 4 below:

Table 4: Test Design Input Parameters.

Parameter	Value	Unit	Comment

Parameter	Value	Unit	Comment
a. Reservoir Data			
Pay Zone Thickness	183	ft	
Average Formation Porosity	0.22	fraction	
Formation Compressibility	3.32E-06	psi-1	Estimated using Hall correlation.
Reservoir Pressure	9449	psi	Estimated current pressure based on RCI from KOCR039 (No production from reservoir)
Reservoir Temperature	229	deg^{O}F	
Reservoir Permeability	1558	md	Mean reservoir permeability calculated from FZI analysis using logs acquired from KOCR039 and 39-ST
b. Well Data			
Well Orientation	Deviated		
Well Radius	0.27	ft	
Well bore Storage (WBS) Coefficient	0.018	bbl/psi	Estimated using the total volume of fluids expected in the wellbore if the shut-in was carried out at the surface. If DHSIT is used at the Nipple, C can be as low as 0.0035 bbl/psi
c. Fluid data			
Fluid Type	Gas		
Gas gravity	0.71		
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model	Fault/Dip closure		
Modelling Approach	Numerical		To capture complexities (fault count and orientation) in the reservoir structure
e. Flow Data for Model Pressure Simulation			
Initial Build Up	24	Hrs	Flow @ 0 MMscf/day
1st Flow Period	4	Hrs	Flow @ 20 MMscf/day
2nd Flow Period	4	Hrs	Flow @ 30 MMscf/day
3rd Flow Period	4	Hrs	Flow @ 40 MMscf/day
4th Flow Period	4	Hrs	Flow @ 50 MMscf/day
Final Build up	48	Hrs	Flow @ 0 MMscf/day

4.2 Scenario/Sensitivity Formulation

PERMEABILITY:

The permeability values used in this design were based on FZI analysis which utilizes the porosity logs acquired from the well. A minimum, most likely and maximum value of 522mD, 1558mD and 2079mD respectively were derived and used in the design.

BOUNDARY MODEL:

The F2000X reservoir Map (Appendix 5) was digitized and used in the design. The reservoir has GWC at 13749 ftss. From the top structure map and cross section (Appendix 5 & 6), the structure has few intra-reservoir faults which are mostly interpreted as non-sealing. A review of the structure also show that the reservoir is fault bounded at the north-east by the boundary fault and at the west, south and south-east. The sealing factors of the major boundary faults are set to zero while intra-reservoir faults are set to 0.5.

SKIN:

Skin value range from the Gbaran Node (Zarama, Koroama, Gbaran and Kolo Creek) have been used to define the skin range for the design. The skin values are 15, 52 and 88 for low, mid and high respectively.

WELLBORE STORAGE:

A wellbore storage coefficient of 0.018 bbl/psi was estimated for surface shut in. The well test design was carried out using this well bore storage as a worst case scenario, in the event of failure or unavailability of the DHSIT. From the derivative plot generated in this test design, this wellbore storage effect (where the well is shut-in at surface), will not mask the reservoir pressure response. However, it is recommended to have the DHSIT to reduce the wellbore storage co-efficient.

Given the above, the scenarios as shown in Figure 1 below were simulated and the generated pressure responses analyzed.

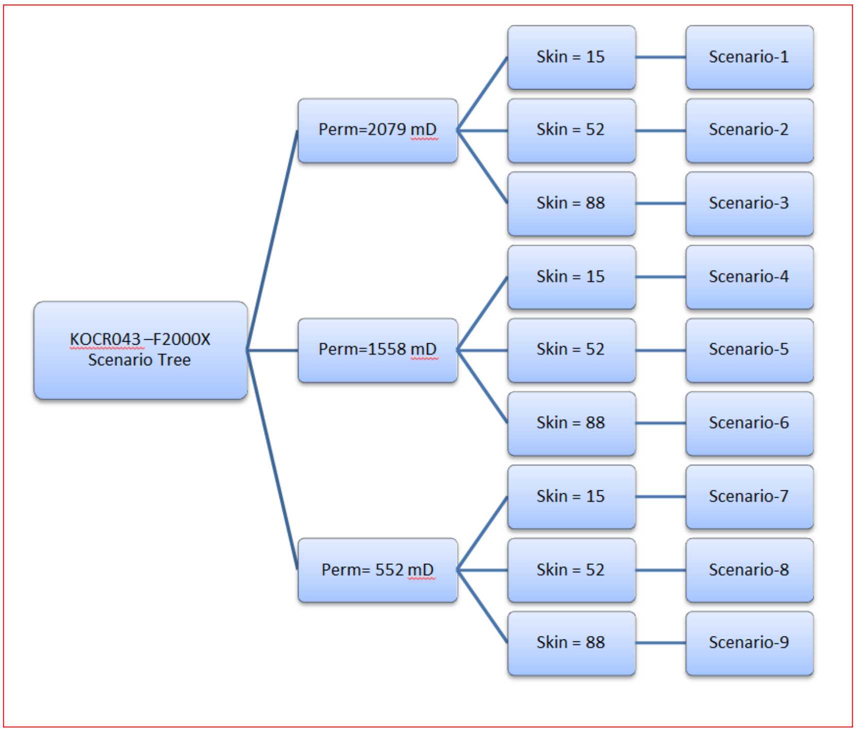


Figure 1: Scenario

4.3 ANALYSIS

Numerical method was used in the test design. The top structure map was digitized and imported into the design model. This ensures that the structural configuration of the reservoir is captured adequately, accounting for the details often approximated in the analytical method.

Simulated pressure responses were generated for the test design using 4-hourly four stepped rates (20, 30, 40, & 50 MMscf/d respectively).

Based on available data from wells which were completed on the interval, the F2000X shows a permeability range of 522mD to 2079mD. These values were based on log data from KOCR039 and 39ST. The initial reservoir pressure value of 9449 psia used in the evaluation was based on RCI from KOCR039 as the reservoir has not produced. The Log-Log plots from the generated pressure are shown in Figure 2 and durations from the sensitivities are listed in Table 5.

The derivative plots for the different scenarios can be seen in Figures 2 and 3. From the figures, the following can be deduced

1. The variation in the skin values did not result in significant distortion of the reservoir behaviour. As the infinite acting radial flow period is clearly observed.
2. The late time pressure response indicated an outer boundary primarily dominated by a boundary fault effect in the various scenarios.
3. With the assumed base-case permeability of 1558 mD, a minimum of 24 hours is required for the final build up test. For the permeability value of 552mD, a minimum of 48 hours is required for the outer boundary effects to be felt by the test and pressure stabilization achieved. The 48 hour build-up from the low permeability has been selected as the build-up duration for the well.

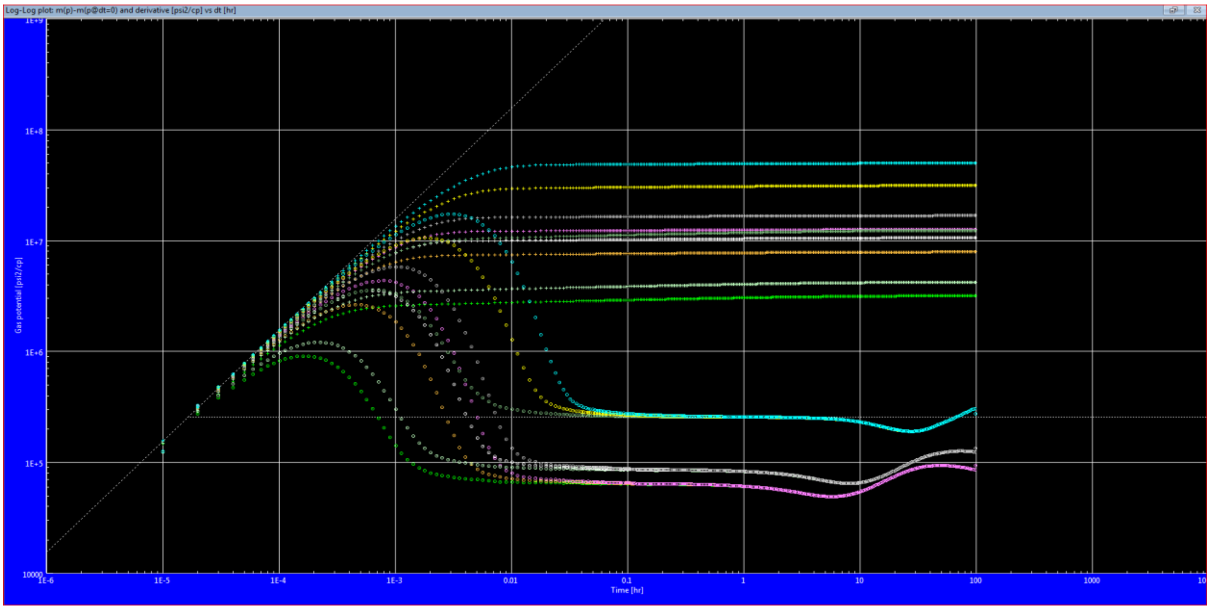


Figure 2: Log-Log plot for All Scenarios

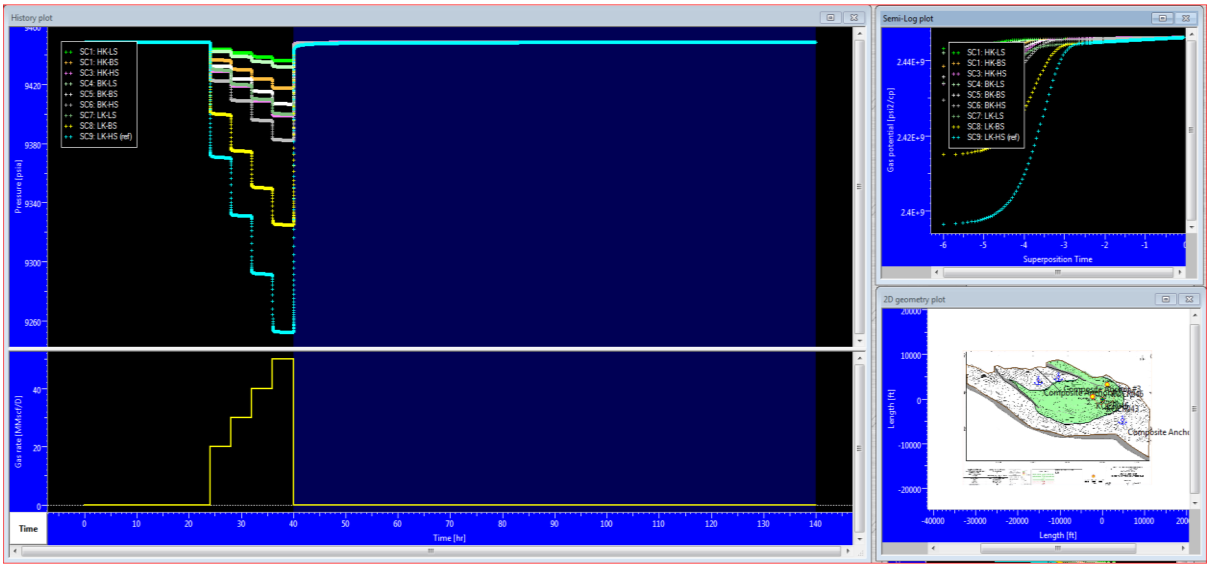


Figure 3: Cartesian, Semi-log plots and Digitized map.

The optimal time for the final build-up was selected based on the need to ensure that the objectives of the test are achieved regardless of the scenario experienced during the actual test. The optimal test time selected is highlighted in Table 5.

Table 5: Scenario Test Times

Scenario	Initial Buildup (Pre Test) hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4thFlow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
S1	24	4	4	4	4	24	64
S2	24	4	4	4	4	24	64
S3	24	4	4	4	4	24	64
S4	24	4	4	4	4	24	64
S5	24	4	4	4	4	24	64
S6	24	4	4	4	4	24	64
S7	24	4	4	4	4	48	88
S8	24	4	4	4	4	48	88
S9	24	4	4	4	4	48	88

5.0 WORKSCOPE SUMMARY

The summary of the Clean-up & MRT work scope is given as follows:

Hold pre-job safety and work scope meeting.

- Check and record wellhead pressures.
- Retrieve monolock plug.
- Pressure and function test CT
- RIH CT to open the FIV, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Lift well with Nitrogen if well does not come unaided.
- Commence well clean-up (Table1).
- Shut-in well for 24 hours for initial reservoir stabilization.
- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,010 ftah).
- Open up well and conduct Multirate test (Table 2).
- Shut in well for 48-hour final build-up test with DHSIT in closed position.
- Carry out SG survey.
- Secure well.
- RD equipment.

NOTE:

- Initial opening of well must be during daylight.
- Bean-up must be done gradually to achieve good bridging behind screen.
- Bean-up should be carried out when flow stabilizes. At each stage, record bean size, gas flow rate, FBHP, FBHT, estimated drawdown, FTHP, FTHT, CGR, WGR, and sand rate.
- Flow well until well is properly cleaned, to a maximum gas rate of 50 MMscf/d. Well is properly cleaned-up when at least 95% of expected FTHP is achieved and WGR is less than 1 stb/MMscf on any bean shown in Table-1 above

6.0 SUPERVISING PERSONNEL

Full time representatives from SPDC, made up of Completion/well test Supervisor and Land East Asset Team Production Technologist or Reservoir Engineer will be on site. This is to ensure the well is properly cleaned prior to the Multi-rate test and that acquired data are of top quality and meet the objectives of the clean-up/well test operations.

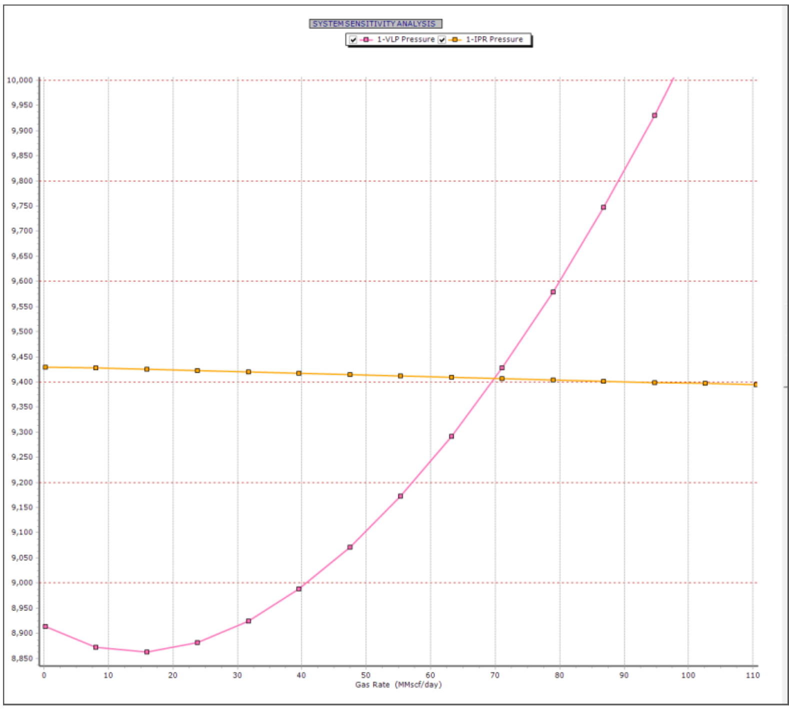
APPENDIX 1: RESERVOIR & COMPLETION DATA

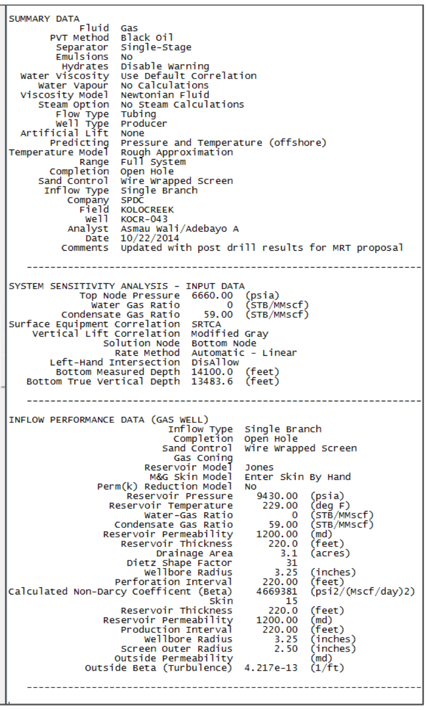
Target Reservoir	F2000X
1. Casing size and Type	7''/Liner
2. Casing Setting Depth (ftah)	13450
3. Top of Sand [ftss/ftah]	13381/ 14100
4. Gross Sand Thickness (Gross) penetrated by KOCR043ST (ft tv)	220
5. Well TD (ftss/ftah)	13601/ 14350
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	13381 – 13601 13439 – 13659 14100 – 14350
7. Length of Completion Interval (ftah)	250
8. a) Top of competent cement (ftah) b) Source of data	6,300 CBL
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 32.39 deg @ 12550
10. Deviation at completion zone	30
11. a) Original reservoir pressure @ datum depth (psia) b) Datum Depth (ftss) c) Present reservoir pressure (psia) @ datum d) Reservoir Temperature (deg F) e) Top of Sand (ftss) f) Reservoir Pressure @ Top of Sand (psia)	9449 13500 9449 229 13381 9430
12. Did RCI indicate abnormal pressures?	Yes (over pressured)
13. Pressure gradient @ top of sand (psi/ft)	0.705
14. a) Is the reservoir fully gas-bearing?	Yes
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC (ft)	Yes (KOCR039ST) 13749 0
16. Distance between lowest completion interval and estimated GWC in well / reservoir (ftss)	154
17. Is there a barrier between lowest completion interval and the present estimated GWC?	No (there are baffles in the reservoir though)
18. Gas S.G. (air=1)	0.71
19. Condensate gravity (API)	39
20. Expected FTHP (psia)*	6660
21. Expected CITHP (psia)	7260
22. Expected Drawdown (psi)*	23
23. Expected PI (scf/d/psi^2)*	219
24. Is sand exclusion installed?	SAS (RESLNK)

*Values are at well potential of 70 MMscf/d

APPENDIX 2: WELL PERFORMANCE PLOTS

KOCR043 Well Performance





SUMMARY DATA

Fluid	Gas
PVT Method	Black Oil
Separator	Single-Stage
Emulsions	No
Hydrates	Disable Warning
Water Viscosity	Use Default Correlation
Water Vapour	No Calculations
Viscosity Model	Newtonian Fluid
Steam Option	No Steam Calculations
Flow Type	Tubing
Well Type	Producer
Artificial Lift	None
Predicting	Pressure and Temperature (offshore)
Temperature Model	Rough Approximation
Range	Full System
Completion	Open Hole
Sand Control	Wire Wrapped Screen
Inflow Type	Single Branch
Company	SPDC
Field	KOLOCREEK
Well	KOCR-043
Analyst	Asmau Wali/Adebayo A
Date	10/22/2014
Comments	Updated with post drill results for MRT proposal

SYSTEM SENSITIVITY ANALYSIS - INPUT DATA

Top Node Pressure	6660.00	(psia)
Water Gas Ratio	0	(STB/MMscf)
Condensate Gas Ratio	59.00	(STB/MMscf)
Surface Equipment Correlation	SRTCA	
Vertical Lift Correlation	Modified Gray	
Solution Node	Bottom Node	
Rate Method	Automatic - Linear	
Left-Hand Intersection	DisAllow	
Bottom Measured Depth	14100.0	(feet)
Bottom True Vertical Depth	13483.6	(feet)

INFLOW PERFORMANCE DATA (GAS WELL)

Inflow Type	Single Branch	
Completion	Open Hole	
Sand Control	Wire Wrapped Screen	
Gas Coning		
Reservoir Model	Jones	
M&G Skin Model	Enter Skin By Hand	
Perm(k) Reduction Model	No	
Reservoir Pressure	9430.00	(psia)
Reservoir Temperature	229.00	(deg F)
Water-Gas Ratio	0	(STB/MMscf)
Condensate Gas Ratio	59.00	(STB/MMscf)
Reservoir Permeability	1200.00	(md)
Reservoir Thickness	220.0	(feet)
Drainage Area	3.1	(acres)
Dietz Shape Factor	31	
Wellbore Radius	3.25	(inches)
Perforation Interval	220.00	(feet)
Calculated Non-Darcy Coefficent (Beta)	4669381	(psi2/(Mscf/day)2)
Skin	15	
Reservoir Thickness	220.0	(feet)
Reservoir Permeability	1200.00	(md)
Production Interval	220.00	(feet)
Wellbore Radius	3.25	(inches)
Screen Outer Radius	2.50	(inches)
Outside Permeability		(md)
Outside Beta (Turbulence)	4.217e-13	(1/ft)

KOCR043 P-Q Curve

APPENDIX 3A: WELL TEST RISKS AND MITIGATION

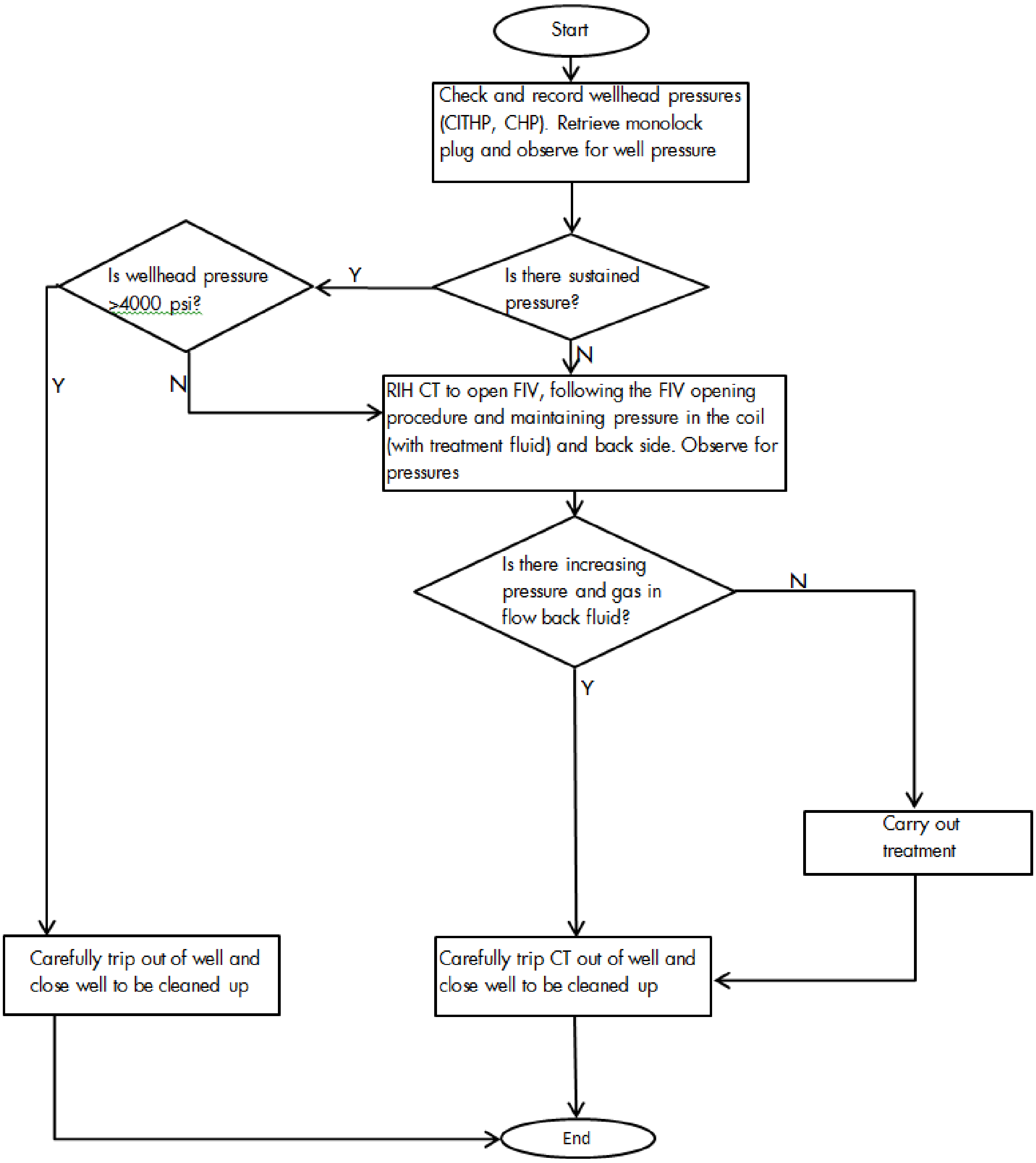
Risk	Consequence	Mitigation
Loss of containment	Blowout, explosion, injury, fatality, loss of equipment	Ensure presence of minimum of 2-barriers at all time during clean-up/MRT operations. Also ensure all HAZID actions are closed-out prior to commencing operation Ensure BOP for the coil tubing unit and all pressure equipment are properly rated and tested at the contractor base and onsite, and these tests are witnessed by SPDC personnel. Check integrity of the valves on the wellhead and TRSCSSV. Install surface readout gauges to monitor pressures at all times
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Ensure that effective glycol is mobilized to site since a high pressure drop is expected, to prevent hydrate formation. Conduct tests on samples of glycol to be used to confirm its adequacy prior to mobilization.
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	Ensure the dimensions of the tools to be RIH are appropriately sized for 7" tubing accessories/profiles ID and 4" FIV and screen
Failure of Downhole Shut-in Tool at deployment, or failure to retrieve the Shut-in Tool and gauges	In-accurate estimate of wellbore storage, impact on well test results, Inability to open well for production.	Ensure tool is checked at the contractor's base and confirmed operational before deploying. Ensure proper and efficient deployment procedures are followed
Noise (Flare)	Damage to personnel eardrum, partial or permanent deafness.	Certified earplugs to be worn by personnel on site.
Radiation/Heat	Unconducive work environment, environmental degradation (loss of economic trees, scotching of flora, fauna migration & death).	Conduct pre-well test modelling of wind flow and speed for optimal location of flare boom. Wear appropriate personal protective equipment at all times in the location. Mobilize water-spraying machines to reduce impact of heat radiation.
Corrosion	Compromised well integrity, uncontrolled emission, harm to flora & fauna population, loss of well, injury, fatality, loss of reputation.	Wellhead have stainless steel clads. Also, acid would not be used during the operation.
Fire Outbreak	Fire outbreak, injury, and loss of equipment, fatality.	Barricade work area, prohibit use of cell phone & smoking around well's perimeter fence, restrict movement of unauthorized persons around work area. Inspect bond wall periodically during and carry out repairs as required.
Night Operations	Poor emergency response, damage to asset, injury, fatality	Obtain night operation approvals, Deploy Emergency Shut Down (ESD) system. Appoint competent Night operations Supervisor.
Emergency	Loss of order, injury, fatality, loss of	Presence of 3-barrier containment Emergency Shut

Risk	Consequence	Mitigation
	equipment.	Down (ESD) system for wellhead, wellsite & test skid. Adopt MOPO (Manual of Permitted Operations) specifying when operations should be stopped if hazard mitigation is not being met. Emergency phone contact will be displayed on site.
Temporary pipe work failure	Uncontrolled flow of hydrocarbon into the environment	Ensure all temporary pipe works are properly secured and tested to the highest pressures expected at this operation
Community disturbance	Disruption of work, delay in execution, cost escalation	Ensure robust engagement of community stakeholders about expectations (flaring heat and noise) during the job execution

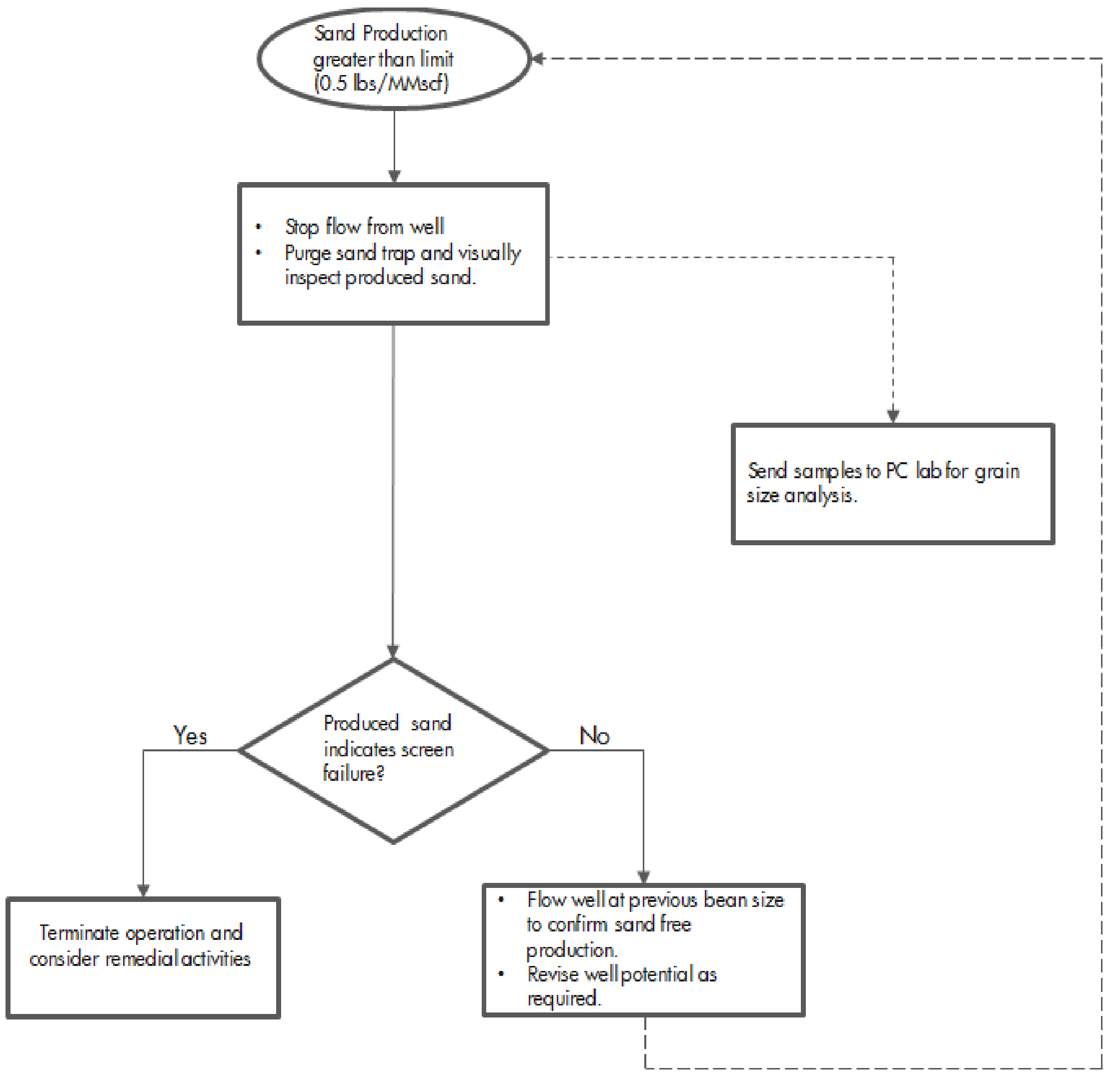
APPENDIX 3B: DEP Table

DEP	Title	Remarks	Accountable DP
25.80.10.10-Gen	Formation Pore Pressure, Fracture Gradient (PP/FG) and Borehole Stability Prediction.	Current reservoir pressure estimate at the top of screen is 9430 psia (See Appendix 11)	RE/PP
25.80.10.11-Gen	Formation Tops, Fault Intersections and Fluid Fill Prediction.	Well already drilled and cased off. Formation tops and fluid prediction as contained in KOCR043 EoWR.	PG
25.80.10.12-Gen	Prepare and Maintain Data in Support of Well Emergencies.	The data to support well emergencies are stored in SharePoint. (See Link) Worst case discharge is estimated at 208 MMscf/d. Please refer to Appendix-7 for WCD plot	PT/WE
25.80.10.14-Gen	Geohazard Assessment for Onshore Exploration, Appraisal and Development.	No geohazard risk. Well is already completed.	PG
25.80.10.15-Gen	Design Logging Program.	No logging operation is planned	PP
25.80.10.18-Gen	Hydrogen Sulphide Prediction for Produced Fluids from New and Existing Wells in Oil and Gas Fields.	H_2S Prediction carried out and signed off. Please refer to Appendix 8.	PG/PT
25.80.10.19-Gen	Sand Failure Assessment for Wells to be Completed and Produced.	Sand failure assessment has been carried out and the well completed with SAS installed for sand control. Sand monitoring would be in place during this clean-up and MRT. See Appendix 3D contingency plan for sand production.	PT

APPENDIX 3C: FIV Opening Contingency Plan



APPENDIX 3D: Kolo Creek 043 Sand production contingency plan



APPENDIX 4: Kolo creek 043 Final Completion Status Diagram

KOLOCREEK-43 FINAL COMPLETION STATUS DIAGRAM

25-Jan-15

CASING

SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn	REMARKS
24"	STOVEPIPE	186	454	Driven		STOVEPIPE
13-3/8"	N80	68	6,500	CLASS G	BTC	Surface Csg
9-5/8"	Q125	54	12,500	CLASS G	SLX	Prod Csg
7"	Q125	32	12,300 - 14,100	CLASS G	SLX	Prod Csg/liner

WELLHEAD (CAMERON CONVENTIONAL)

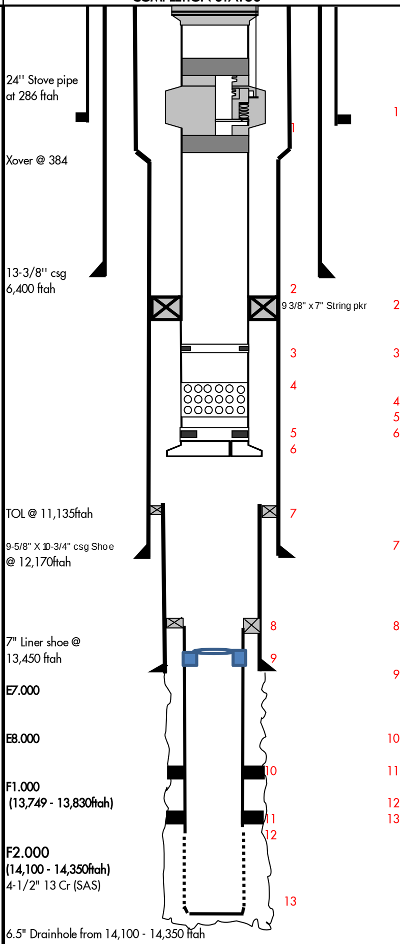
ITEM	TYPE	SIZE	WP (PSI)
INST. FLANGE		7-1/16''	10,000psi
GATE VALVE		6-3/8''	10,000psi
XMAS TREE CAP		6-3/8'' Tree Cap x 5K	10,000psi
XMAS TREE		7" Compact XMT Assy x 6-3/8" Tree Cap	10,000psi
SEAL ASSY		7" NOM	10,000psi
TUBING HANGER		7"x 13 5/8" Compact; 13 Cr. Hyd 563	10,000psi
SEAL ASSY PACKOFF		13-5/8" Nom x 10-3/4" O.O csg	10,000psi
CSG HGR		13-5/8" x 10-3/4"	10,000psi
COMPACT HOUSING		13-3/8" BTCx 13-5/8" Flange Lock	10,000psi

TUBING

STRING	SIZE	WT.	GRAD.	TYPE		HOLE	DESCRIPTION	RESERVOIR
					MAX Deviation: +/- 33.52 deg @ 8,610 T0 13,607 ftah			
					DFE (RT - CELLAR): 58 FT	N/A		
SSS	7"	32/35	L80/P110		RT - TOP XMT:xxxft		Open Hole with SAS Sand Control	F2000
						Drill-in Fluid Type / Properties		
					RT - Compact H: xxx ft	Completion Fluid Type / Properties:		
						Gas Pressure Gradient / Pressure:		

7" PRODUCTION STRING

SAND | COMPLETION STATUS

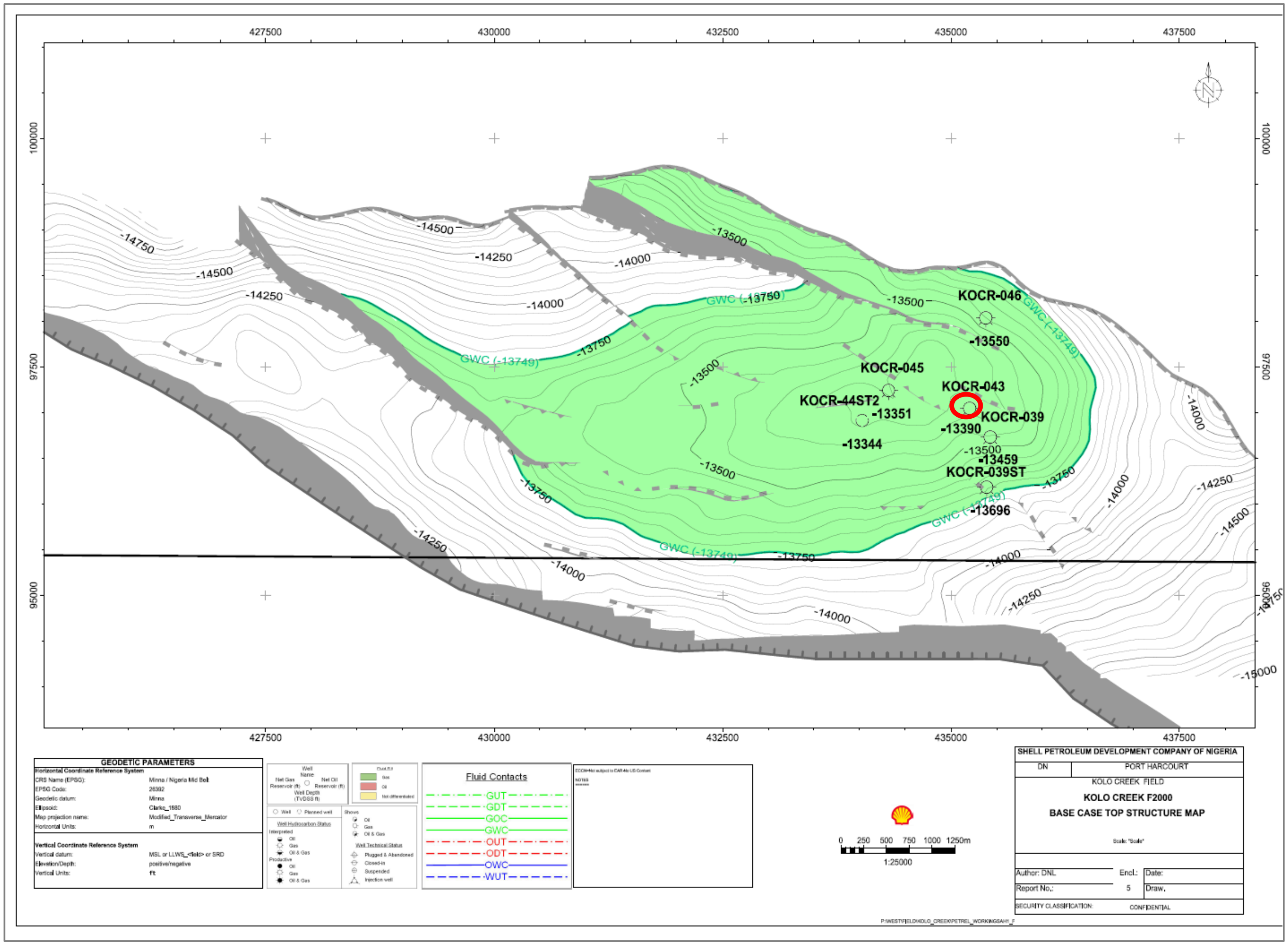


	Top Depth (ftah)	Length (in)	ID (in)	OD (in)	DESCRIPTION
	0.00	1.20	6.004	13.320	Tubing Hanger
	3.00	4.36	6.094	7.660	Hanger Nipple
	42.36	124.76	**6.004**	**7.000**	**7" 35# VM110HCSS Vam Top tubing joint**
1	182.00	8.71	4.562	7.990	7" TRSCSSV H563 13 Cr 29ppf w/c 'RQ' LOCK Profile
	206.28	**7,394.92**	**6.094**	**7.000**	**7" 35# VM110HCSS Vam Top tubing joint**
	7,601.20	**407.66**	**6.094**	**7.000**	**7" 32# Cr P110 Vam Top tubing joint**
	8,008.86	**2,959.92**	**6.094**	**7.000**	**7" 32# Cr L80 Vam Top tubing joint**
2	**10,980.82**	5.34	5.875	8.310	Permanent Packer 9-5/8"x7", 13 Cr H563 bxp
3	11,010.18	1.98	4.500	7.060	RPT Nipple Vam Top B X P S13Cr
	11,013.45	10.79	6.205	7.760	7" 13Cr L80 pup joint
4	11,024.21	40.34	6.185	7.760	Perforated Tubing Joint, 7" Vam Top box by pin
5	11,065.43	1.59	4.313	6.150	RN' Nipple 4-1/2" Fox-K, 13Cr (4.313" Bore, 4.1" NoGo)
6	11,080.36	1.04	6.460	8.300	Wireline re-entry guide, 7" 13Cr
	11,081.14				End of Tubing
7	11,135.00	11.98	6.130	8.400	Cadmium EXR Liner Hanger 9 -5/8" x7"
					OPEN HOLE STANDALONE SCREEN ASSEMBLY
8	13,246.22	20.29	3.880	5.860	Crossovers + Pup joint + 7" VCA Packer
	13,266.51	39.60	3.958	5.060	4-1/2" 12.6# Blanks Vamtop Box x Pin 13Cr L80
	13,306.11	10.10	3.910	4.960	Pup joint,41/2" 12.6# vamtop HC pin x Vamtop Box 13Cr L80
9	13,316.21	16.78	2.940	5.520	**4 1/2" 12.6# Vamtop HC B X P FIV Assy**
	13,332.99	1.23	3.860	4.940	Crossover: 4 1/2" 12.6# Vamtop HC Box x 4-1/2'' Vamtop pin
	13,334.22	10.44	3.910	4.960	Pup joint; 4-1/2" 12.6# vamtop Box x Pin 13Cr L80
	13,344.66	367.86	3.958	4.500	4-1/2" 12.6# Blanks Vamtop Box x Pin 13Cr L80
10	13,712.52	42.77	3.900	5.500	4-1/2" 12.6# vamtop Box x Pin 13Cr L80 Swell packer
	13,755.29	116.93	3.958	4.500	4-1/2" 12.6# Blanks Vamtop Box x Pin 13Cr L80
11	13,872.22	42.48	3.900	5.500	4-1/2" 12.6# vamtop Box x Pin 13Cr L80 Swell packer
	13,914.70	157.94	3.958	4.500	4-1/2" 12.6# Blanks Vamtop Box x Pin 13Cr L80
12	14,072.64	276.46	3.958	5.060	4-1/2" 12.6# PRO-WELD TOP Direct Wire Wrap Vam Top Box x Pin,225 micron Mesh
13	14,349.10	0.90		5.000	4-1/2" Bull Nose
	14,350.00				
	14,350.00				Well TD

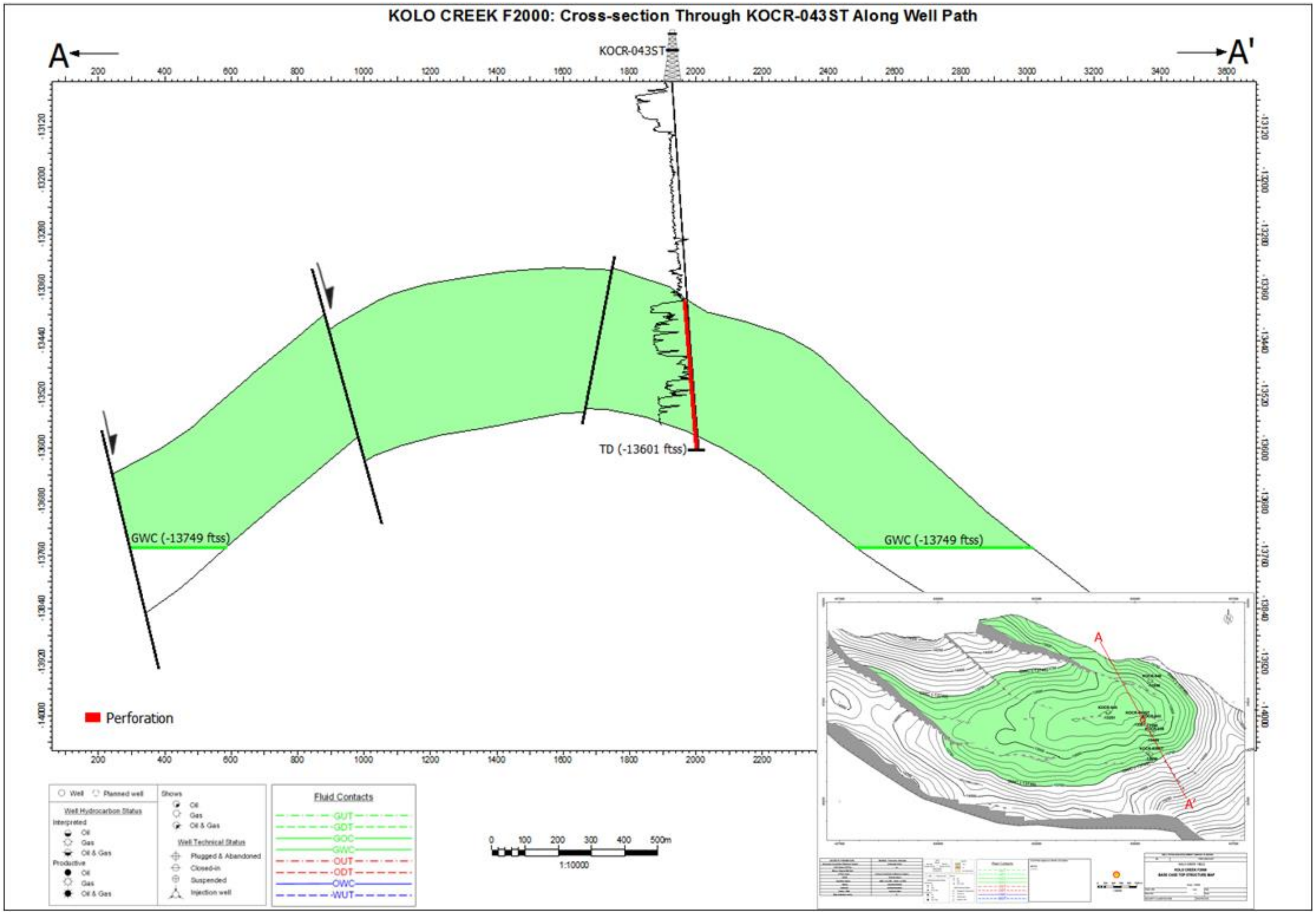
NOTE: All depths are top depths along hole BDF. Completion materials are 13 Cr

TD:	AUTHOR:	DATE COMPLETED:	COMPLETED BY:		CHECKED BY:	APPROVED BY:
14,350ftah	Ben Nwoye	26-Jan-15	**Temitope Alalade**	**Godwin Lawson** **Oluwatobi Ugoh**	**Ben Nwoye**	**Stanley Akanegbu**

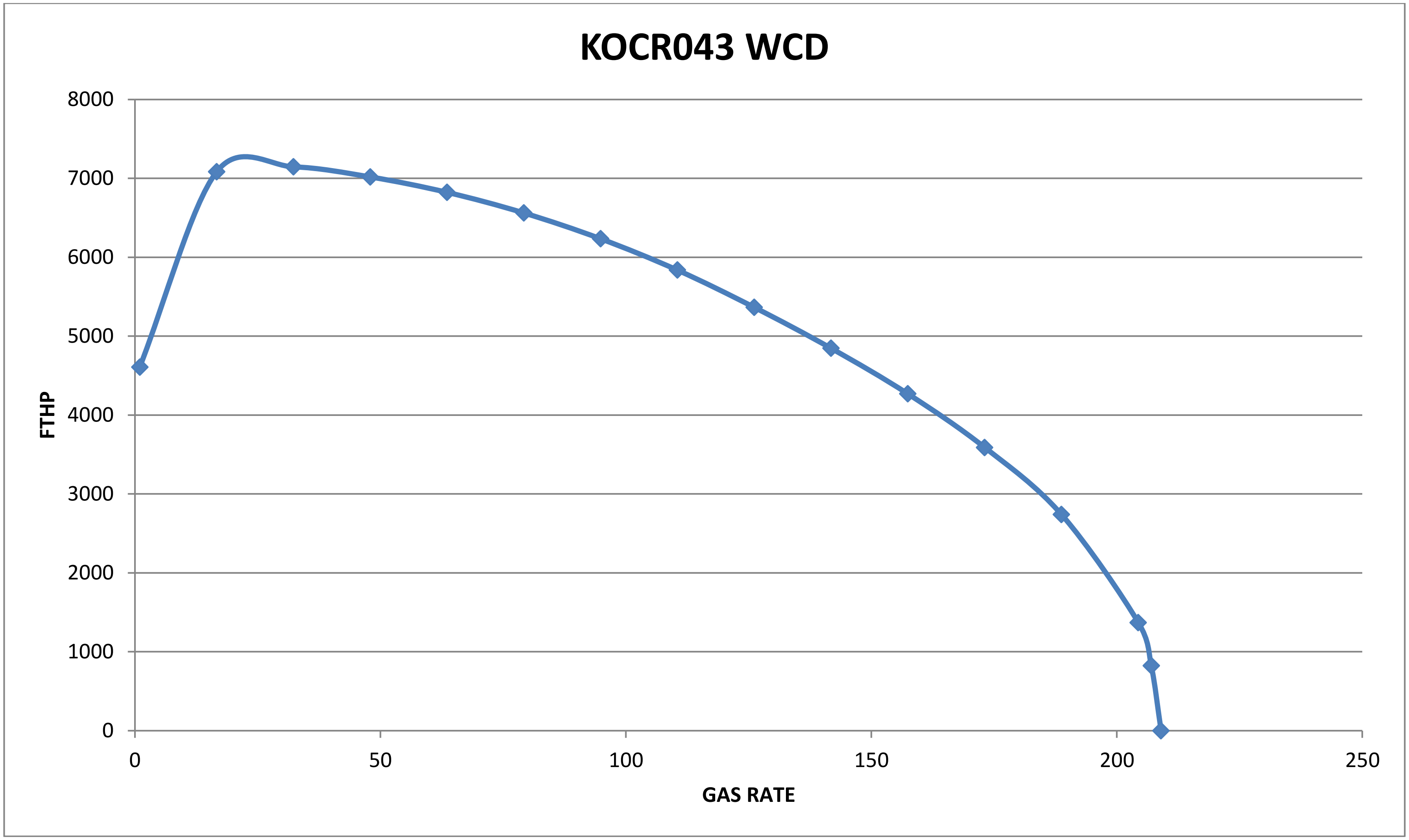
APPENDIX 5: Top Depth Map of the F2000X sand



APPENDIX 6: Cross section along KOCR043 well path



APPENDIX 7: Worst Case Discharge Plot



APPENDIX 8: KOCR043 H2S Prediction

KOCR043T H_2S PREDICTION

Introduction

The consequence of the presence of H2S is loss of life and material integrity. This document contains prediction of naturally occurring H_2S concentration and souring potential for KOCR043T well based on available data.

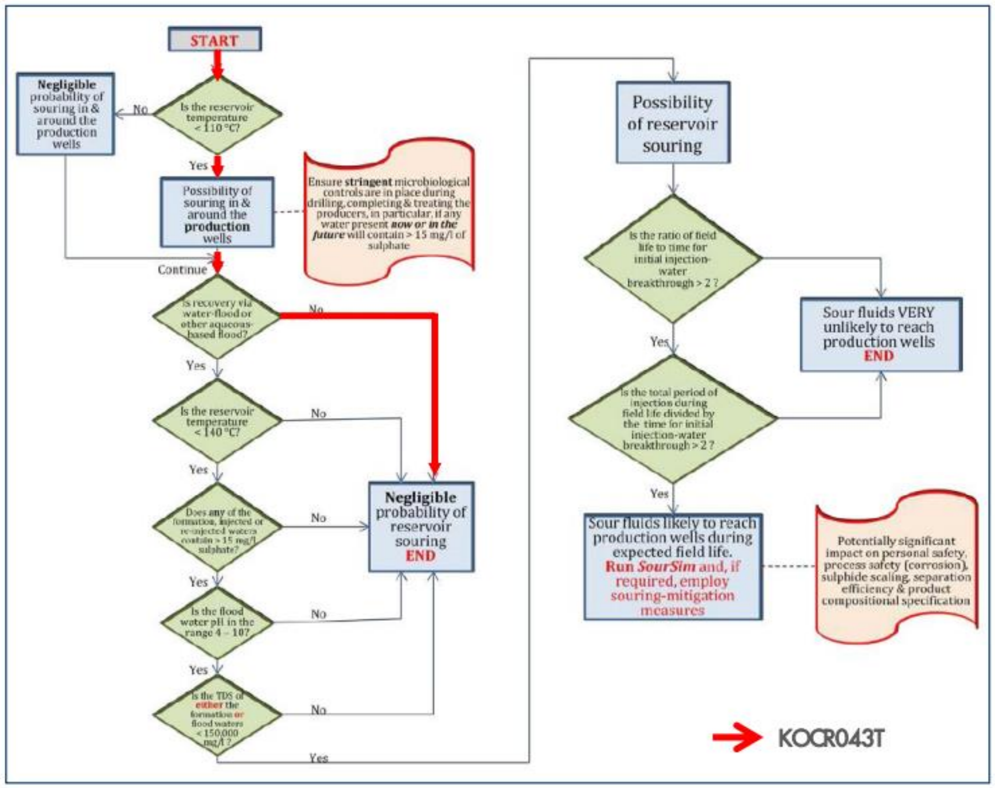
Naturally Occurring H_2S Concentration

- KOCR043T is completed on the F2000 reservoir.
- PVT analysis available for F2000X reservoir shows no presence of H_2S
- H_2S has not been encountered in KOCR oil & NAG wells producing in the Gbaran nodal area.
- Naturally occurring H_2S concentration is therefore predicted to be 0%mol

Souring Potential

- Souring potential is a function of expected reservoir temperature
- Expected reservoir temperature is 109 °C, (229°F) however, no waterflood is planned for the field.
- Hence, the souring potential is negligible. (see SPA tool)
- Gas testers and appropriate PPE's will be utilized during completion and well open up as additional mitigation.

Souring Potential Assessment for KOCR043T



Prepared by: Kassim Hamzat	Reviewed by	Approved by:
Checked by: Emesi, John Nnadi, Magnus Akunesiobike, Jonathan	Nwankwo, Cosmas Oluwajuyigbe, David	Ugboaja, Remmy UGBOAJA REMMY Digitally signed by UGBOAJA REMMY Date: 2017.01.26 19:35:50 +01'00'

APPENDIX 9: KOCR043 Clean up and Well Test Cost Estimate

S/N	Service Description	Minimun Cost ($)
1	Well Test Services	**$486,134.28**
2	WHM Ops	**$32,928.98**
3	CT/N2 Services	**$241,567.97**
4	HP Pumping Ops	**$85,956.80**
5	WT Support	**$394,780.93**
6	SL Support	**$54,611.44**
7	Water Facilities	**$16,931.81**
8	IT Support	**$4,412.10**
9	SPDC Logistics	**$98,675.02**
10	FTO	**$9,266.67**
11	Security	**$26,600.00**
	TOTAL	**$1,451,865.99**

APPENDIX 10: KOCR043 Expected Annular Fluid Expansion

Estimated Incremental AFE pressure and volume for 50 MMscf/d flow without annulus bleed down

String Annulus	Incremental AFE pressure (psi)	Incremental AFE Volume (bbl)
9-5/8" Production Casing (B annulus)	4665	7.8
7" Production Tubing (A annulus)	5877	5.6

Notes:

1. If CHP exceeds expected AFE pressure or bled down volume exceeds AFE volume then, CHP investigation required.
2. Casing should be monitored closely and bled down as per program because expected AFE pressure exceeds the MAASP calculated for A & B annulus.

APPENDIX 11: F2000 Pore Pressure Estimation

The pore pressures for the F2000 reservoir were estimated using pressure cell method. RCI data from KOCR-039ST was used to obtain the pore pressure model.

The pressure at the top of screen was obtained by extrapolating the pressure from the datum depth (13500 ftss) using fluid gradients measured from the F2000 reservoir in KOCR-039ST.

Uncertainty in fluid gradient was considered in estimating the high, base and low case pore pressures. The top of screen was established based on the completion tally, thus uncertainty in depths was eliminated.

All reservoirs shallower than the F2000 have been cased-off (please see appendix 4), thus the pore pressure estimation was carried out for only the F2000 which will be open to flow during the Clean-up / MRT operation. The table below presents the range of formation gradients estimated for the F2000 reservoir based on KOCR-043ST, 045 & 046.

Reservoir	Min formation gradient, KOCR046 (psi/ft)	Ref formation gradient KOCR043ST (psi/ft)	Max formation gradient, KOCR045 (psi/ft)
F2000	0.698	0.704	0.706

The pore pressure table and plot are presented below.

Pore Pressure Estimation Plot

FIELD : *KOLO CREEK*

Well : *043ST*

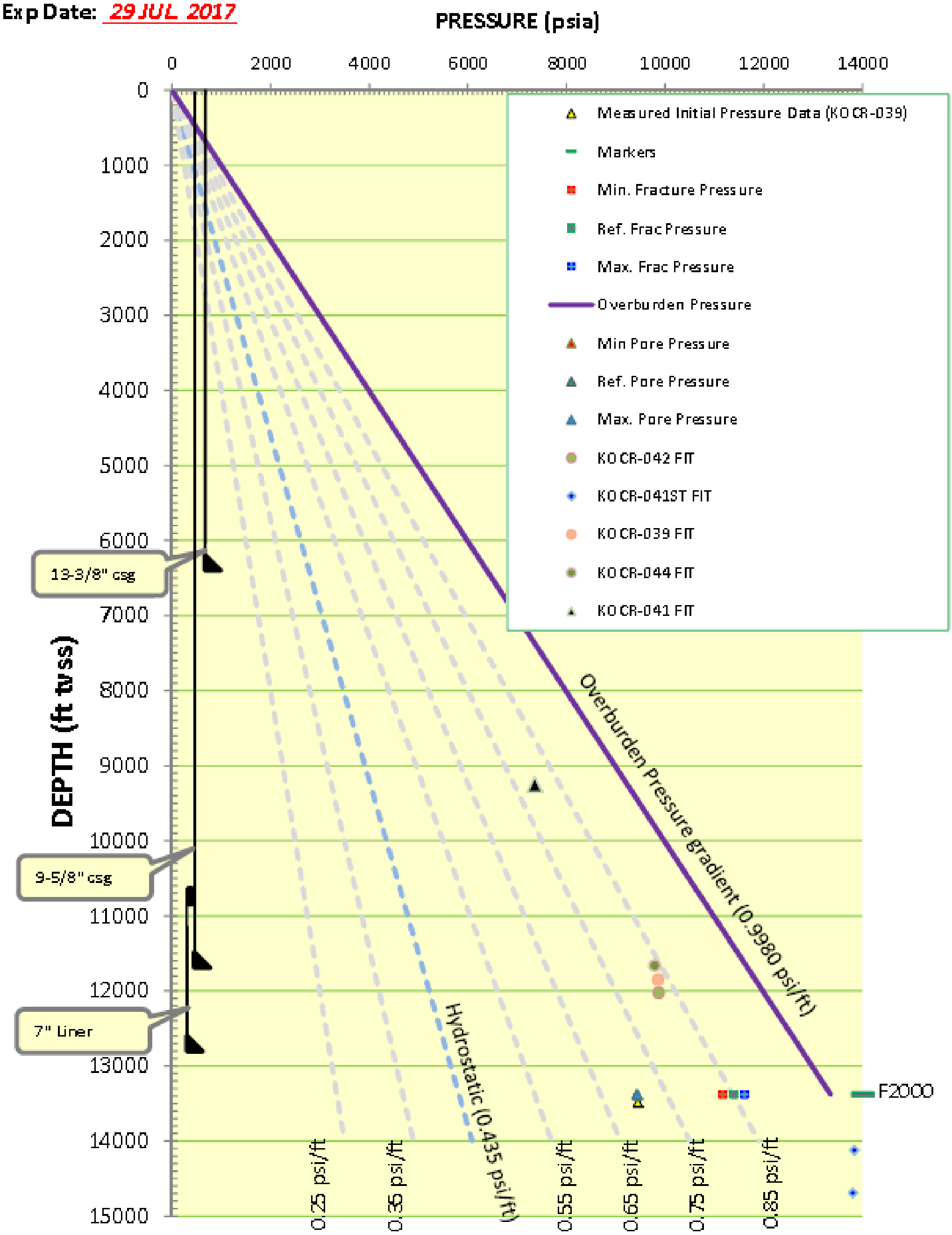
Revision : *3.0*

Issue Date: *30 JAN. 2017*

Exp Date: *29 JUL 2017*

Pore/Fracture Pressure Prediction Plot

(Pressure at Top Reservoir Depth)



Prepared by : DIKE, AHUNANYA Date: 30/1/2017

PP Check/Approved by: LAOYE, ABIODUN / ODEGBESAN, OLUSEYI Date: Oluseyi Odegbesan Digitally signed by Oluseyi Odegbesan Date: 2017.01.31 11:26:42 +01'00'

Pore Pressure Estimation Table

FIELD:	KOLO CREEK
WELL NAME:	043ST
PLATFORM/RIG :	**Mobile Test Separator**
PREPARED BY / CHECKED BY	DIKE AHUNANYA / LAOYE ABIODUN
ISSUED DATE :	30 January 2017
REVISION NO:	3.0
SPUD DATE:	07 August 2013
EXPIRY DATE:	29 July 2017

Pore Pressure Prediction at Top Reservoir for KOCR-043ST

	TV-Depth of Pressure Prediction and Reference Depth (e.g., ss or bdf)			Fluid Type Prognosis at Top of Sand along Well Trajectory	Is Reservoir Developed	Formation Pore Presure Prognosis at Top of Screen along Well Trajectory					Formation Pore Pressure Gradient at TOS					Fracture Gradient Prognosis at Top of Screen along Well Trajectory					
Formation	Shallow (ft-ss)	Most Likely (ft-ss)	Deep (ft-ss)	Reference Case	(Y/N)	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 (psia/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	Remarks
F2000	13381	13381	13381	Gas	N	9427	9427	9430	9434	9434	0.704	0.704	0.705	0.705	0.705	0.835	0.835	0.851	0.868	0.868	Reservoir is in the Over-pressured regime. All shallower reservoirs have been cased off.

Prepared By: DIKE AHUNANYA (Name) SPDC-UPO/G/DNF (Team Indicator) 30/01/2017 (Date)

PP Check/Approved By: LAOYE, ABIODUN / ODEGBESAN, OLUSEYI (Name) Oluseyi Odegbesan Digitally signed by Oluseyi Odegbesan Date: 2017.01.31 11:23:22 +01'00' (Signature) (Date)

Validity Date: 29-Jul-17