THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOROAMA-007 WELL CLEAN-UP/TEST PROPOSAL

September 2016

Well No	KOROAMA-007
Reservoir	D7000X
Estimated Duration	18 days
Cost	$1,451,865.99 mln

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1.0 BACKGROUND

Koroama-007 is a gas development well that was drilled to provide a drainage point on the D7000X reservoir and develop 24.04 Bscf of gas reserves at an initial production potential of 90 MMscf/d. The well was spudded on the 7th of October 2013, drilled to a TD of 9,916 ftah (8,798 ftss), and completion operation ended on 3rd June 2014. The well partially penetrated the D7000X sand at 8,736 ftss, 18 ft deeper than prognosis and encountering a gross gas column of 62 ft tvd.

It was drilled and completed as a Single String Single (SSS) gas producer on the D7000X gas reservoir with 7" 13Cr tubing equipped with Tubing Retrievable Surface-Controlled Subsurface Safety Valve (TRSCSSSV). A 7" PDHG was initially planned but could not be run in the well due to operational constraints. External gravel pack (EGP) was installed across the sand face for effective sand control.

Koroama D7000 reservoir is one of the major reservoirs in the Koroama field accounting for 15% of the total Gas initially in place in the field with a GIIP of 337 Bscf. Production started in the reservoir July 2013 with the coming on-stream of Koroama-004 well. As at May 2016, the cumulative production from the reservoir was 72.5Bscf.

It is proposed to clean up the well to about 50 MMscf/d to remove drilling and completion debris and fluids and also conduct Multirate test to ca. 50 MMscf/d on the D7000X interval. This is due to the limit of the contractor's facilities, as the proposed offtake of the well is 90 MMscf/d of gas production.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to get rid of 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 Gbaran CPF as part of the wells delivering gas to the NLNG T1 – T6. 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 summary of the clean-up work scope is given as follows:

- RIH CT with impact hammer to break the flapper at 9,747 ftah (Confirm flapper is completely broken and no any other restriction through the EGP)
- RIH CT to 5 feet above TD (9,911 ftah) while pumping KCl to displace Thixsal mud.
- Clean up by making minimum of three passes, jetting 10% HCl across the screen
- Circulate hole with KCl to displace spent acid after 30 mins and POOH CT
- Pump nitrogen (if required) to lift until well is confirmed to sustain natural flow
- Clean-up well as per program (Table-1)
- Shut-in well for 24 hours for initial reservoir stabilization (KOMA004T producing from same reservoir should also be closed-in to avoid interference).
- RIH Slickline to install memory P/T gauges with programmed DHSIT at R nipple (9518 ftah).
- Open up well and conduct Multirate test
- Shut in well for 25 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.
- Neutralize acid in flow back tank using soda ash (K-35) before dumping at the flow station.
- Bean-up must be done gradually to achieve good bridging behind EGP.
- 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, not exceeding a maximum gas rate of 50 MMscf/d. Well is properly cleaned-up when at least 80% of expected FTHP is achieved on any bean shown in Table-1 above
- All temporary pipe connections must be properly secured and tested to expected pressures

2.0 WELL CLEAN-UP DESIGN

During the clean-up operation, KCl will be pumped to displace Thixsal mud. Then, 10% HCL is jetted across the gravel pack screen in several passes. The well should be flowed long enough to allow sufficient time to offload well on each bean and while monitoring sand production. If there is significant sand production, flow will be stopped and sand trap bled down for inspection after every bean change. All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

2.1 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
- 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 (Compulsory requirement)
- Mono- Ethyl Glycol (To mitigate hydrates at low rates)

2.2 Well Clean-Up Operation

The well cleanup operation will commence with unloading operation via coiled tubing. The clean-up will then commence from choke $36/64^{th}$ (Note bean should be gradually increased to $36/64^{th}$). There will be gradual bean-up in stages of 4/64th up to choke 64/64. 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 WGR ca. 0 bbl/MMscf is achieved. Thereafter, shut-in the well for 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

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

Table 1: KOROAMA-007 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*	40	0	2358	6	48	Take sample, check for sand, measure FTHP.
30	48	0	2353	3	68	Take sample, check for sand, measure FTHP.
40	56	0	2336	3	91	Take sample, check for sand, measure FTHP.
50	64	0	2296	4	120	Take sample, check for sand, measure FTHP.

*Clean-up criteria as shown below must be achieved on bean 40/64 as a minimum

Clean up criteria
Stabilized THP for 1 hour
BSW of liquid sample </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 psia

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

3.1 Initial Build-up Period

- Close in well at choke manifold for 24 hours for an initial build-up 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). Deepest gauge should be at "R – Nipple" (ca.9518 ftah).
- Monitor surface read-out of CITHP for pressure stabilization before proceeding to MRT. Also KOMA004T which is producing from the same reservoir should be shut-in to minimize interference.

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) (1/64th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period* (hr)	Expected Drawdown (psi)	Comments
20*	40	0	2358	4	48	Take sample, check for sand, measure FTHP.
30	48	0	2353	4	68	Take sample, check for sand, measure FTHP.
40	56	0	2336	4	91	Take sample, check for sand, measure FTHP.
50	64	0	2296	4	120	Take sample, check for sand, measure FTHP.

**Note KOMA004T (producing from same reservoir) should be closed-in after clean-up, kept close until MRT/Build-up are completed. Bean up should be carried out when flow stabilizes and FTHP & BSW are stable for at least 1 hour.*

- 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 25 hours (Final Buildup duration determined from section 4.0) and subsequently commence Static Gradient Survey (See Table 3 below).

3.3 Final Build-up and Static Survey Period

- Confirm well has been closed in for 25 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 and compare to real time fiber optic data.
- Close TRSCSSSV and line up well to production.
- Handover well to production.

Table 3: Static Gradient Survey Stops.

Depth Tag (d)	Depth (d)	di-1-di	Time at depth	Comment/Basis for Stops Selection
	ftah from DFE [DFE Elevation = 34 ft]	**ft**	**Minutes**	
Deepest Survey Depth	9518	-	0	Deepest Survey depth. R nipple Depth
1st Stop	9498	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	9478	20	10	
3rd Stop	9458	20	10	
4th Stop	9258	200	10	2nd Set of Stops: 3 Stops at 200ft intervals to ensure accurate estimate of well fluid gradient
5th Stop	9058	200	10	
6th Stop	8858	200	10	
7th Stop	8658	200	10	3rd Set of Stops: 3 Stops at 500ft intervals to ensure accurate estimate of well fluid gradient
8th Stop	8158	500	10	
9th Stop	7658	500	10	
10th Stop	7158	500	10	4th Set of Stops: 3 Stops at 1000ft intervals to ensure accurate estimate of well fluid gradient
11th Stop	6158	1000	10	
12th Stop	4158	2000	10	
13th Stop	2158	2000	10	5th Set of Stops: 3 Stops at 2000ft intervals to ensure accurate estimate of well fluid gradient
14th Stop	158	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 production data as detailed in Table 2. Pressure simulations were generated based on the rates in section "e" of Table 4. 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 0.01 psi/hr as seen in SAPHIR (Note that priority was given to the time to seeing an outer boundary effect). 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
a. Reservoir Data			
Pay Zone Thickness	80	ft	Average D7000 Reservoir thickness
Average Formation Porosity	0.25	fraction	KOMA-07 EOWR
Formation Compressibility	3.32E-06	psi-1	Estimated using Hall correlation.
Reservoir Pressure	3025	psi	Estimated current pressure based on MBAL
Reservoir Temperature	153	F	KOMA-07 EOWR
Reservoir Permeability	1680	md	Mean reservoir permeability seen by well logs across D7000 Reservoir
b. Well Data			
Well Orientation	Vertical		
Well Radius	0.35	ft	
Well bore Storage (WBS) Coefficient	0.1041	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 0.005 bbl/psi
c. Fluid data			
Fluid Type	Gas		
Gas gravity	0.74		KOMA-07 EOWR
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model			
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	25	Hrs	Flow @ 0 MMscf/day

4.2 Scenario/Sensitivity Formulation

PERMEABILITY:
The permeability values used in this design represent P10, P50 and P50 average Permeability estimates from log evaluation in 3 wells (KOMA 001, 002 & 010). A minimum, most likely and maximum value of 450mD, 1680mD and 3640mD respectively were derived and used in the design.

BOUNDARY MODEL:
The TOP structure Map (Appendix 5) was digitized and used in the design. The reservoir is bounded by an OOWC at 8844 ftss but also has an OGOC at 8833 ftss, giving rise to a small oil rim of 11 ft. From the top structure map and cross section (Appendix 5&6), the reservoir geometry is relatively simple. A review of the structure shows that the reservoir is fault bounded in all direction. This formed the basis for digitizing the map with closed boundaries. This is supported by the behaviour of the pressure as seen in this reservoir which indicates that the reservoir is bounded on all sides and therefore no pressure support. Also, with no intra reservoir faults, the outer boundary to be seen by the well will likely be the boundary faults.

SKIN:
No data was available to evaluate the possible skin values that may exist in reality. However skin values of 5, 7 and 10 (selected based on expected skin range for External Gravel pack completion) was studied.

WELLBORE STORAGE:
A wellbore storage coefficient of 0.1041 bbl/psi was estimated for surface shut in. For down-hole shut in at the R Nipple, the wellbore storage was estimated to be ca. 0.005 bbls/psi.
The well test design was carried out using well bore storage of 0.1041 bbl/psi 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.

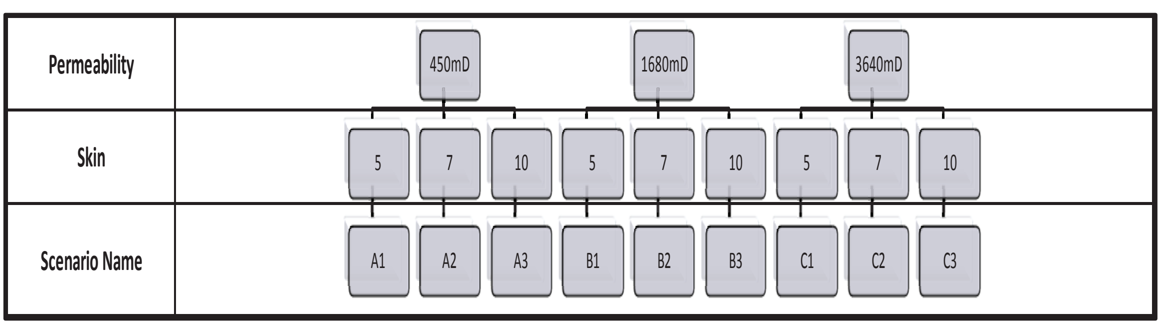


Figure 1: Scenario

Table 5: Reservoir Model & Wellbore model Parameters

Parameter	Value	Unit
Well & Well Bore Parameters		
Well bore Model	Constant Wellbore Storage	
Wellbore Storage Coefficient (C)	0.1041	bbl/psi
Skin Factor	7 (base case sensitivity)	
Reservoir & Boundary Parameters		
Pi	3025	Psia
K.h	134,400 (base case sensitivity)	md.ft
Reservoir Model	Homogenous	

5.3 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 minute 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 study conducted for Koroama field as captured in the Koroama FDP of 2007, the D7000 reservoir show a permeability range of 500mD to 3500mD. These values were based on log data from KOMA 002. However, the reservoir permeability range used in the design was based on the range of permeability derived from well logs as seen by 3 wells (KOMA001, 002 and 010). KOMA 004 MRT result would have helped in the choice of a permeability range, it was however inconclusive. Design sensitivity analyses were carried out for reservoir permeability values of 450mD, 1680mD, 3640mD. A reservoir pressure value of 3025 psia was used in the evaluation based predicted pressure from material balance modeling for the reservoir at September 2016. The initial reservoir pressure of 3,841 psia could not be used considering that KOMA 004 completed on this reservoir is in production.

The derivative plots for the different scenarios can be seen in figures 2, 3 and 4. From the figures, the following can be deduced

1. The variation in the skin values will not result in any significant distortion to the expected reservoir behaviour and no impact on the time to the outer boundary from the test.
2. The late time pressure response indicated an outer boundary primarily dominated by initially a parallel fault boundary effect and then an intersecting fault behaviour in the case of permeability of 1680mD.in the 450mD permeability scenario, the type of outer boundary effect is most likely the parallel fault within the time frame of test, however, it requires more time to see the other boundaries. In the 3640mD permeability scenario, a slight deviation was observed around 40 - 50 hours of shut-in. this is most likely to be caused by the effects of the pressure transient seeing all the boundaries of the reservoir. However, more time is required to be able to define properly the outer boundary effect seen by that response.

3. With the assumed base-case permeability of 1680mD, a minimum of 10 hours is required for the final build up test to start seeing the outer boundary effect. For the permeability value of 450mD, a minimum of 25 hours is required for the outer boundary effects to be felt by the test and pressure stabilization achieved. The outer boundary effects will be felt as early as 5 to 10 hours for the high permeability value scenario. Based on the above, a minimum of 25 hours is required by the test in all scenario to feel the effect of the outer boundary effect.

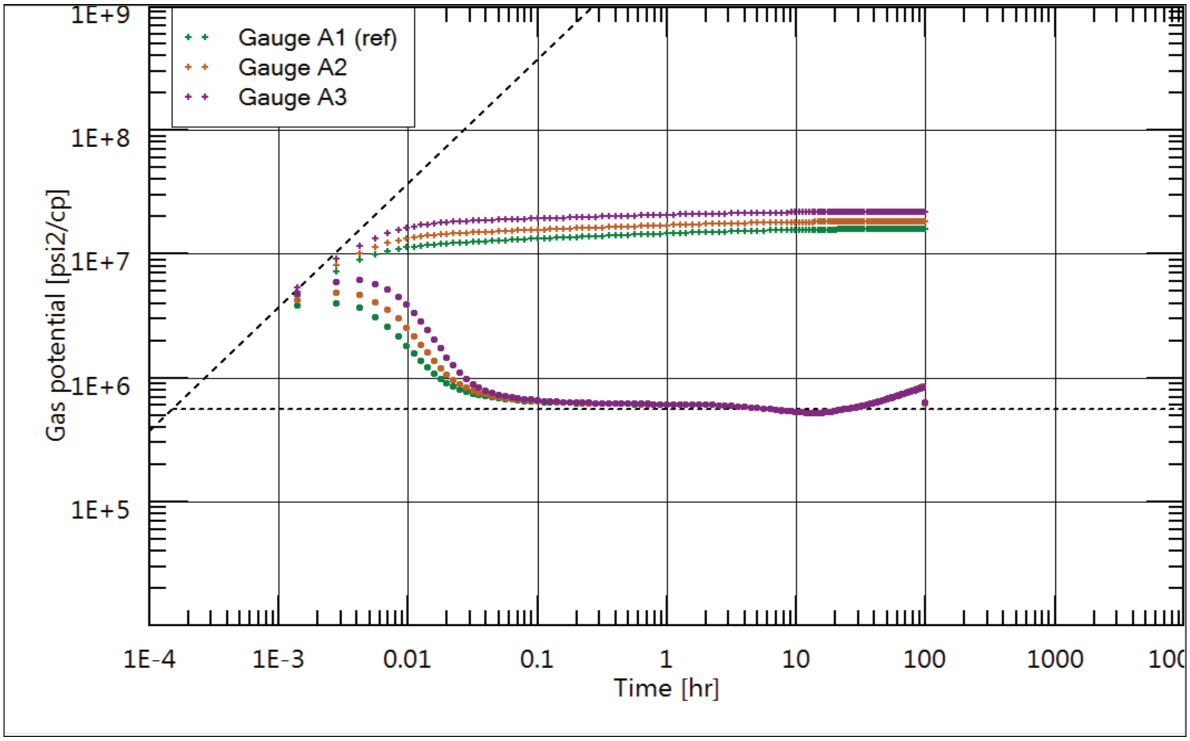


Figure 2: Log-Log plot for Scenario A1 (Perm/Skin: 450mD/5), A2 (Perm/Skin: 450mD/7), A3 (Perm/Skin: 450mD/10)

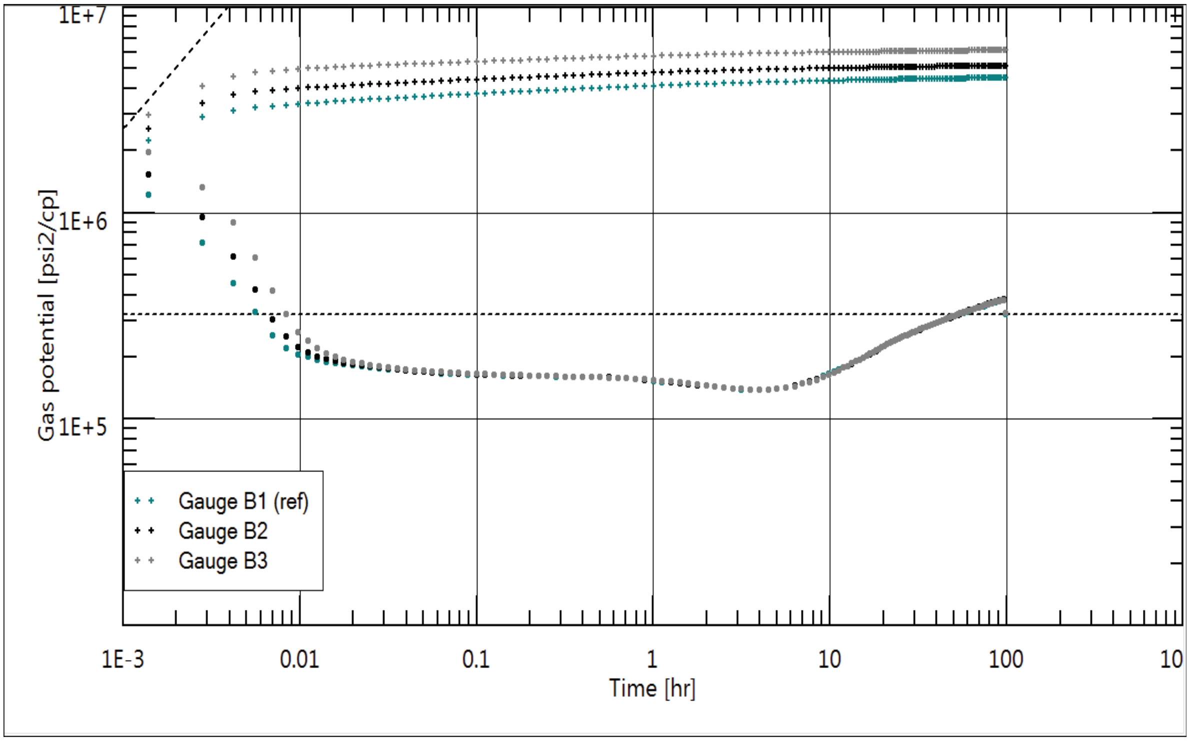


Figure 3: Log-Log plot for Scenario B1 (Perm/Skin: 1680mD/5), B2 (Perm/Skin: 1680mD/7), B3 (Perm/Skin: 1680mD/10)

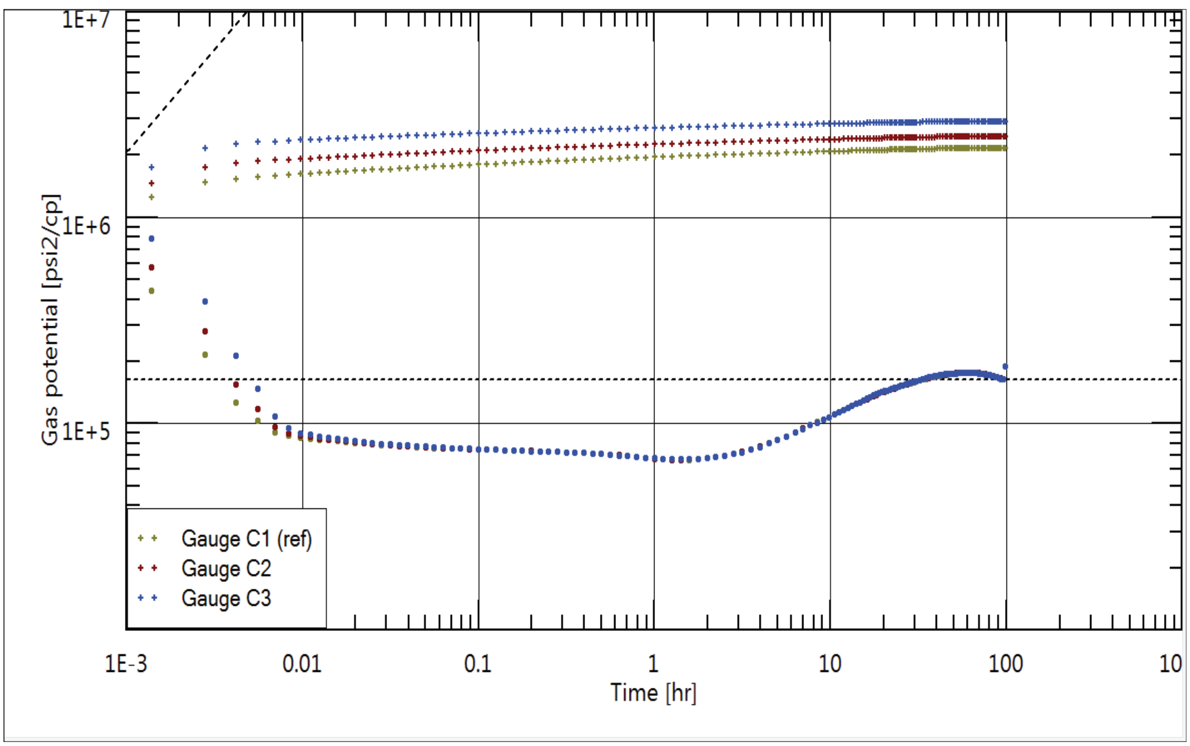


Figure 4: Log-Log plot for Scenario C1 (Perm/Skin: 3640mD/5), C2 (Perm/Skin: 3640mD/7), C3 (Perm/Skin: 3640mD/10)

Table 6: Scenario Test Times

Scenario	Initial Buildup (Pre Test) hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
A1	24	4	4	4	4	30	70
A2	24	4	4	4	4	30	70
A3	24	4	4	4	4	30	70
B1	24	4	4	4	4	20	60
B2	24	4	4	4	4	20	60
B3	24	4	4	4	4	20	60
C1	24	4	4	4	4	10	50
C2	24	4	4	4	4	10	50
C3	24	4	4	4	4	10	50

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 and considering that the low case starts to feel the effect of the outer boundary effect around 25 hours, the optimal time will be that minimum. The optimal test time selected is as detailed in the table below.

Table 7: Optimal Test Timing

Scenario	Initial Buildup (Pre Test) hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
A1	24	4	4	4	4	25	65

5.0 WORKSCOPE SUMMARY

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

- Hold pre-job safety and work scope meeting.
- Check and record wellhead pressures.
- Retrieve NRV.
- Pressure and function test CT.
- RIH CT to 5 feet above TD (9,911 ftah) while pumping KCl to displace Thixsal mud.
- Confirm ceramic flapper at 9747 ftah is completely broken and no any other restriction though the EGP
- At TD, switch over to 10% HCl acid, make three passes across the screen and allow to soak for 30 mins.
- Lift well with Nitrogen if well does not come unaided.
- Commence well clean-up (Table 1).
- Shut-in well for 24 hours for initial reservoir stabilization.
- RIH Slickline to install memory P/T gauges with programmed DHSIT at R nipple (9,5 18 ftah).
- Open up well and conduct Multirate test (Table 2).
- Shut in well for 25 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.
- Neutralize acid in flow back tank using soda ash (K-35) before dumping.
- Bean-up must be done gradually to achieve good bridging behind EGP.
- 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 60 MMscf/d. Well is properly cleaned-up when at least 90% 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.

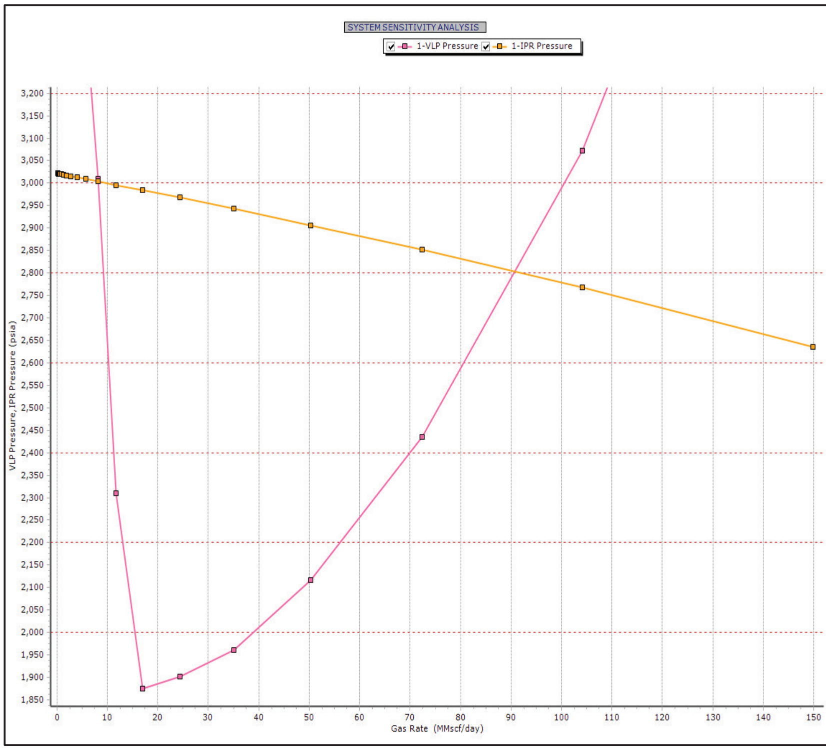
APPENDIX 1: RESERVOIR & COMPLETION DATA

Target Reservoir	D7000X
1. Casing size and Type	9-$^5/_8$''/Production casing
2. Casing Setting Depth (ftah)	9,841
3. Top of Sand [ftss/ftah]	8,736/9,830
4. Gross Sand Thickness (Gross) penetrated by Koroama-007 (ft tv)	62
5. Well TD (ftss/ftah)	8,798/9,916
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	8,740 - 8,798 8,811- 8,869 9,841 - 9,916
7. Length of Completion Interval (ftah)	75
8. a) Top of competent cement (ftah) b) Source of data	7,300 CAST-CBL
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 39.73° @ 8,832
10. Deviation at completion zone	39.51^0
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)*	3,841 8,833 3,025 153 8,736 3,025
12. Did RCI indicate abnormal pressures?	No (ref KOMA-010 RCI)
13. Pressure gradient @ top of sand (psi/ft)	0.4147
14. a) Is the reservoir fully gas-bearing?	No
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC (ft)	Yes 8,833 (KOMA-002) No (11 ft oil rim)
16. Distance between lowest completion interval and estimated GOC in well / reservoir (ftss)	35
17. Is there a barrier between lowest completion interval and the present estimated GWC?	No
18. Gas S.G. (air=1)	0.74
19. Condensate gravity (API)	44
20. Expected FTHP (psia)**	2103
21. Expected CITHP (psia)	2450
22. Expected Drawdown (psi)**	223
23. Expected PI (scf/d/psi^2)**	70
24. Is sand exclusion installed?	Yes (EGP)

* Estimated reservoir pressure is based om MBAL prediction as at October 2016
**Values are at well potential of 90 MMscf/d

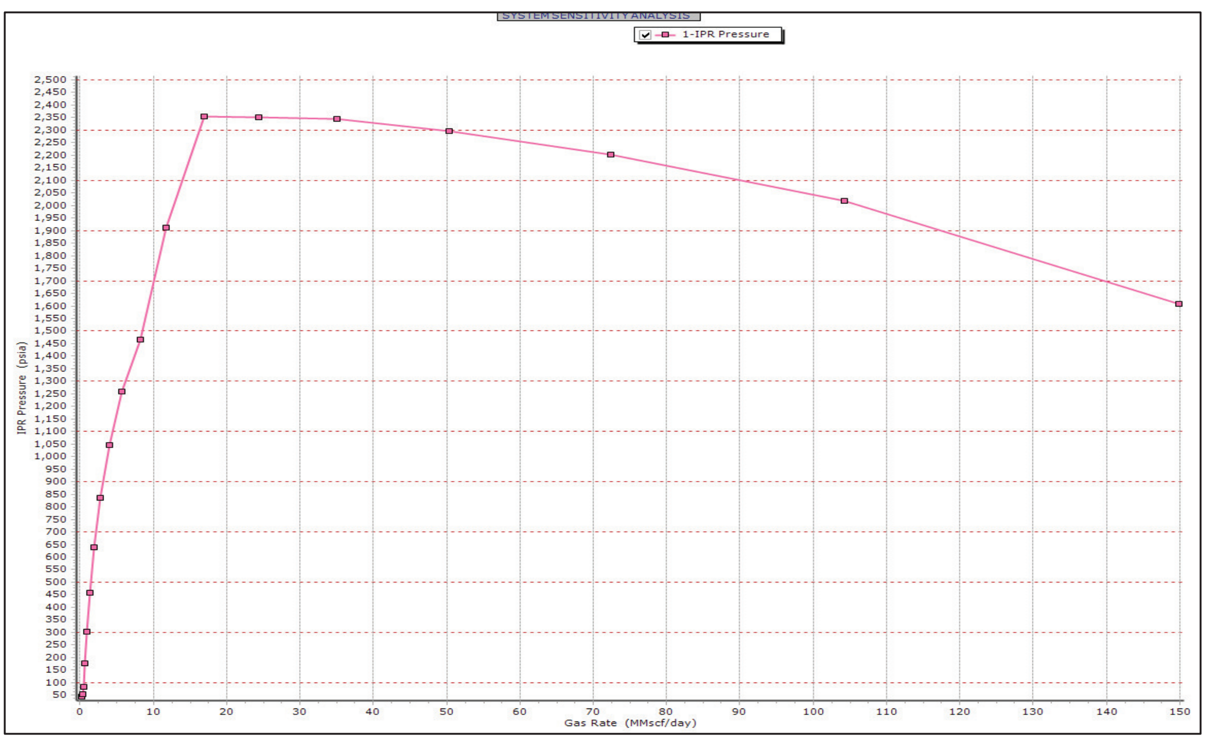
APPENDIX 2: WELL PERFORMANCE PLOTS

KOMA-7 MRT Well Performance




```
SUMMARY DATA
                Fluid  Gas
           PVT Method  Black Oil
            Separator  Single-Stage
            Emulsions  No
             Hydrates  Disable Warning
      Water Viscosity  Use Pressure Corrected Correlation
          Water Vapour  Calculate Condensed Water Vapour
      Viscosity Model  Newtonian Fluid
         Steam Option  No Steam Calculations
            Flow Type  Tubing
            Well Type  Producer
      Artificial Lift  None
           Predicting  Pressure and Temperature (on land)
    Temperature Model  Rough Approximation
                Range  Full System
           Completion  Open Hole
         Sand Control  None
         Inflow Type   Single Branch
                 Date  17/11/2006

   ---------------------------------------------------------

SYSTEM SENSITIVITY ANALYSIS - INPUT DATA
            Top Node Pressure  1464.70  (psia)
Surface Equipment Correlation  SRTCA
    Vertical Lift Correlation  Modified Gray
                Solution Node  Bottom Node
                  Rate Method  Automatic - Geometric
       Left-Hand Intersection  DisAllow
        Bottom Measured Depth   9841.0  (feet)
   Bottom True Vertical Depth   8811.0  (feet)

   ---------------------------------------------------------

INFLOW PERFORMANCE DATA (GAS WELL)
           Inflow Type  Single Branch
            Completion  Open Hole
          Sand Control  None
            Gas Coning
       Reservoir Model  MultiLayer - dP Loss In WellBore
Perm(k) Reduction Model  No
  Reservoir Temperature  145.00  (deg F)

   ---------------------------------------------------------
```

KOMA-7 P-Q Curve.



APPENDIX 3A: CRITICAL WELL TEST OPERATIONS RISKS/MITIGATION

Risk/Description	Consequence	Likelihood / Impact (L/M/H)	Mitigation
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	L/M	Ensure the dimensions of the tools to be RIH are appropriately sized for 3-1/2" tubing accessories/profiles ID
Emergency to spill, loss of containment	Loss of order, injury, fatality, loss of equipment	L/H	Ensure presence of 3-barriers at all time during clean-up/MRT operations. Also ensure all HAZID actions are closed-out prior to commencing operation
Hydrocarbon under pressure from kick or blowout	Explosion, loss of containment, injury, fatality and environmental pollution	L/H	Check integrity of the valves on the wellhead and WRSCSSV are integrity. Install surface readout gauges to monitor pressures and ensure BOP for the coil tubing unit is fully functional
Corrosive cleaning chemicals	Corrosion, environmental contamination.	L/H	Confirm that Nitrogen for lifting is tolerated by tubing/casing material.
Failure of Downhole Shut-in Tool	In-accurate estimate of wellbore storage, impact on well test results	M/M	Ensure tool is checked at the contractor's base and confirmed operational before deploying

APPENDIX 3B: GAS WELL TEST RISKS/MITIGATION

Risk	Consequence	Mitigation
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Glycol will be injected at low gas rates to combat possible hydrate formation. At gas high rates, tubing temperatures are high enough to combat hydrate.
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.	13%Cr, completion material eliminates the need for corrosion inhibitor injection. Also wellhead have stainless steel clads.
Fire Source	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.
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 equipment.	Presence of 3-barrier containment Emergency Shut 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 before commencing operation

APPENDIX 3C: 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 is 3,150 psia (ref KOMA-11 PPP –April 2016) Note: No drilling activity would be carried out during the operation	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 KOMA007 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 210 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.	No H_2S production reported in KOMA004 producing the same reservoir 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 done as an input to the Well proposal. Well has been completed with OHGP installed for sand control	PT

APPENDIX 4: Koroama-007 Final Completion Status Diagram

KOROAMA 7 (ex TBUV 5) COMPLETION SCHEMATIC 4-Jun-14

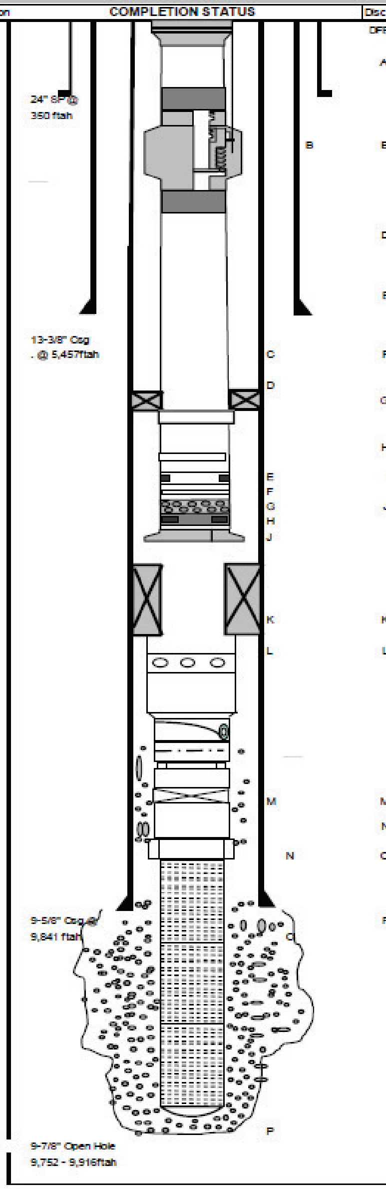
CASING							WELLHEAD (Surface Metal Seal 2 Step System)			
SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn		ITEM	TYPE	SIZE	WP
20"	Stove Pipe		350	Driven		Stovepipe	XMAS TREE	SMS UNITIZED	7-1/16" x 13-5/8" Flange block x 7-1/16" outlet	5,000 psi
							TREE CAP	Cameron	7-1/16" c/w 7.060" Bore	5,000 psi
13-3/8"	K55	68	5,545.00	Class G	BTC	Surf Csg	GATE VALVE	Cameron	7-1/16" c/w 7.060" Bore	5,000 psi
10-3/4"	C90	60.7	300.00	Class G	SLX	Prod Csg	ACTUATOR VALVE	Cameron	7-1/16" c/w 7.060" Bore	5,000 psi
9-5/8"	N80	47	10,760	Class G	SLX	Prod Csg	TUBING HANGER	Cameron	13-5/8" Nom X 7" w/CL Prep and optic fibre	5,000 psi
							COMPACT HOUSING	Cameron	13-5/8"	5,000 psi
							GATE VALVE	Cameron	2-1/16" c/w 2.060" Bore	5,000 psi

TUBING								
STRING	SIZE	WT.	GRAD.	TYPE	MAX Deviation: 25.84 deg at 7003ftah	HOLE	DESCRIPTION	RESERVOIR
					RT - Top XMT = 23 ft	9-7/8"	EGP	E1000X
SSS	7"	29#	13Cr	HYDRIL 563	DFE (RT - Compact Housing)= 34 ft			
					XMT = 7ft	Drill-in Fluid Type / Properties	Thixal Mud 0.49 - 0.52 psi.ft, YP 22 -26 lb/100 ft2	
						Completion Fluid Type / Properties:	Filtered Inhibited NaCl Brine _ 0.47psi/ft	
						Workover Fluid Type / Properties:		

7" Completion Production String

Sand/ Deviation — COMPLETION STATUS

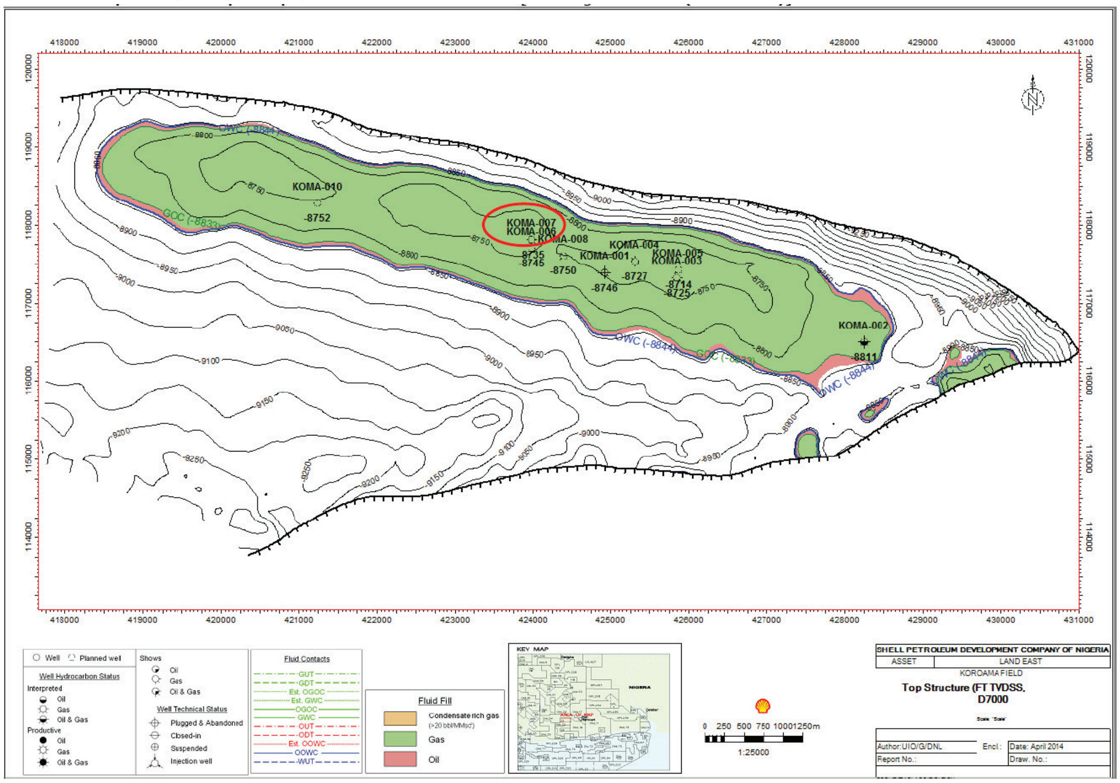
E1000X



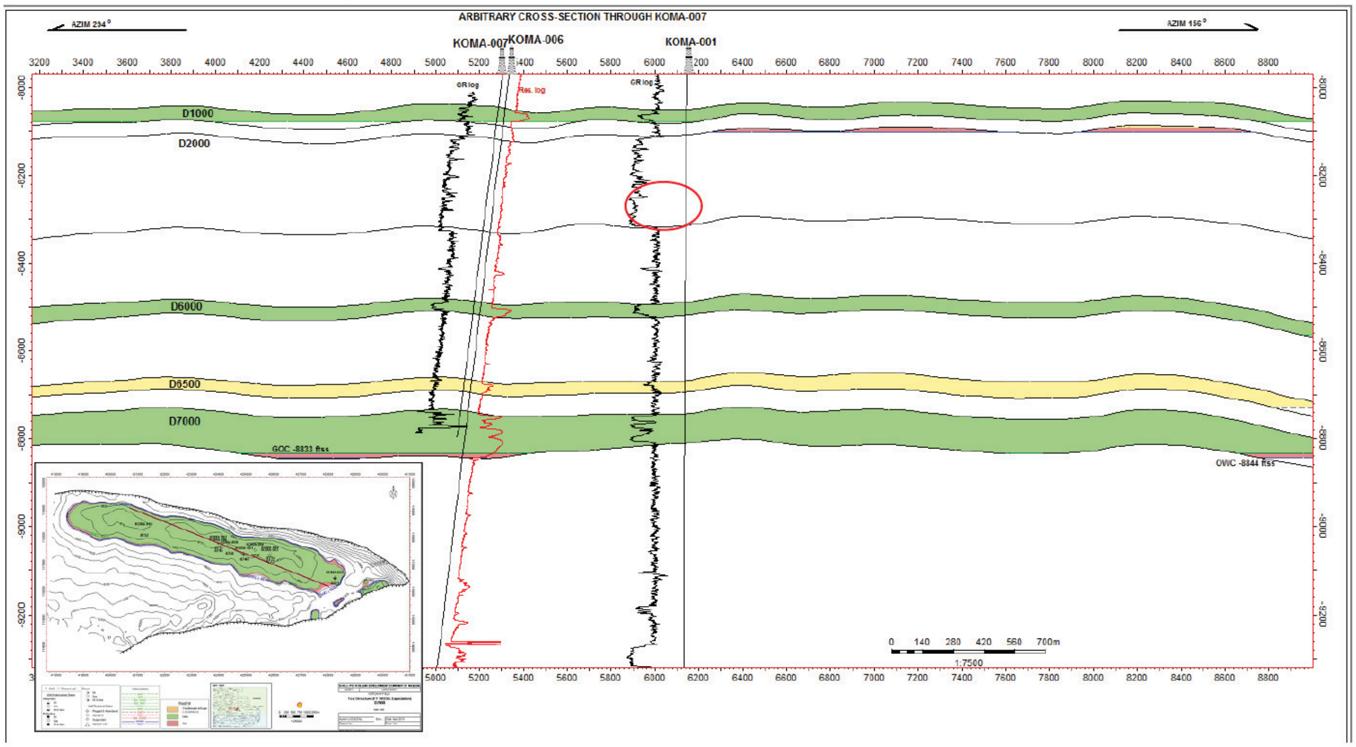
Disc	Top Depth	Length	O.D.	I.D.	DESCRIPTION
DFE	0.00	34			**ELEVATION**
A	34.00	0.86	13.32	6.184	Cameron SSMC Hanger, 7" H563 B, 13Cr. RIGHT HAND RELEASE
	34.86	8.57	7.660	6.179	Pup Joint, 7" 29# H563 P-P 13CR L80
	43.43	122.76	7.670	6.190	Tubing Joint, 7" 29# H563 B-P 13CR L80
	166.19	9.69	7.670	6.190	Pup Joint, 7" 29# H563 B-P 13CR L80
	175.88	9.69	7.670	6.120	Flow Coupling; 7" H563 B-P 13CR L80
B	186.67	11.89	8.380	5.875	HES SP TRSV(Non Equalizing) 7", 29 # H563 Box x Pin, 13Cr
	197.46	9.35	7.670	6.122	Flow Coupling; 7" H563 B-P 13CR L80
	206.81	4.56	7.670	6.197	Pup Joint, 7" 29# H563 B-P 13CR L80
	211.37	9,236.81	7.670	6.170	Tubing Joint, 7" 29# Vam Top B-P 13CR L80 (c/w with H56 X/Os)
	9,448.18	9.69	7.670	6.170	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,457.87	5.90	8.220	5.870	HES THT Packer 9-5/8", 47-58.4#: 7" 29# NS-CC Box x Pin, 13Cr
D	9,463.77	4.91	7.670	6.200	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,468.68	40.92	7.670	6.190	Tubing Joint, 7" 29# H563 B-P 13CR L80
	9,509.60	9.65	7.670	6.170	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,519.25	1.71	7.680	5.825	HES R Nipple,5.825": 7",29# H563 Box x Pin,13Cr
E	9,520.96	4.91	7.670	6.170	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,525.87	40.91	7.670	6.190	Tubing Joint, 7" 29# H563 B-P 13CR L80
	9,566.78	9.67	7.680	6.160	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,576.45	5.17	8.260	6.080	HES Auto-Fill Sub: 7", 29# H563 Box x Pin,13Cr
F	9,581.62	5.86	7.68	6.160	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,587.48	9.66	7.68	6.160	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,597.14	5.17	8.260	6.080	HES Mirage Plug: 7", 29# H563 Box x Pin,13Cr
G	9,602.31	5.68	7.690	6.18	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,607.99	41.08	7.170	6.184	Perforated Tubing, 7" 29# H563 Box x Pin 13Cr
H	9,649.07	2.21	7.676	5.500	RN Landing-Nipple 5.625, 7" 29# H563, Box x Pin 13Cr, NO-GO = 5.500" Pressure Rating: 7900 Psi
I	9,651.28	4.86	7.690	6.184	Pup Joint, 7" 29# H563 Box x Pin 13Cr
	9,656.14	0.83	8.310	6.450	Wireline Re-entry Guide, 7" 29# H563 Box, 13Cr
J	9,656.97				
	9,694.13	7.88	8.434	6.000	Range, 8.450 In. Max OD, 6.000 In. Min ID, 6.000 In. Seal Bore ID-Min, 94.7 In. Length, 325 Deg. F, Std/CO2 Service, 13% Chrome Matl, 80000 psi Min Yield, HNBR Element Matl, 6 7/8-4 AC-LH Latch Type, 7 5/8 API-STC Box, 812VGP9012-F
K	9,702.01	6.55	7.701	6.880	Upper Extension,7 5/8" 29.7# BTC Pin x Pin 13Cr L80
	9,708.56	4.56	8.108	6.000	Closing Sleeve,7 5/8" BTC Box x 7" BTC Pin,13Cr L80
L	9,713.12	21.64	7.695	6.540	6.509 In. Min ID, S13Cr p110, 10730 psi Pressure Rating, Std/CO2 Service,
	9,734.76	1.75	7.674	5.812	Indicator Coupling/Receptacle, 7 5/8-39.00 AB-HD-L Box x Pin, 7.655 In. Max OD, 5.800 In. Min ID, 25.52 In. Length, 101290789 (12MPC12) Mating Collet, Std/CO2 Service, 12P98580 (S/N: S2636928-05)
	9,736.51	9.63	7.692	6.646	Lower Extension,7"29# Pin x Pin 13Cr L-80
	9,746.14	1.13	8.139	6.270	Adapter: 7 5/8" 39# BTC Box x 7" 26# BTC Pin,13Cr (S/N: MS 18382-1-3/3)
	9,747.27	2.97	8.121	5.009	Ceramic Flapper Valve,7" BTC Box x Pin,13Cr L-80
	9,750.24	2.05	7.668	5.052	Shear Out Safety Joint,7" BTC x 5 1/2" Pin,13Cr L-80
M	9,752.29	0.96	7.426	4.882	Adapter, 6 5/8" 24# BTC Box x 5 1/2" 17# LTC Pin,13Cr (S/N: 18382-2-1/3)
N	9,753.25	80.70	8.250	4.694	BLANK ASSEMBLY, 5 1/2-20.00 API-LC, HAL GRADE L-80 13% CHROME, 480 - SPIROLIZER
O	9,833.95	81.05	8.250	4.694	Gauge,HAL Grade L-80 13Cr,Centralizer Type: Spirolator with stop rings set screw type
	9,915.00	0.97	6.130	N/A	Bull Plug, 5 1/2" 24# LTC Box,13Cr
	9,916.00				
P					

DATE COMPLETED:	DRAWN BY:	CHECKED BY:	APPROVED BY:
	Ibitomihi S. Mike	Imoyo Olusola	Ibrahim Yahaya

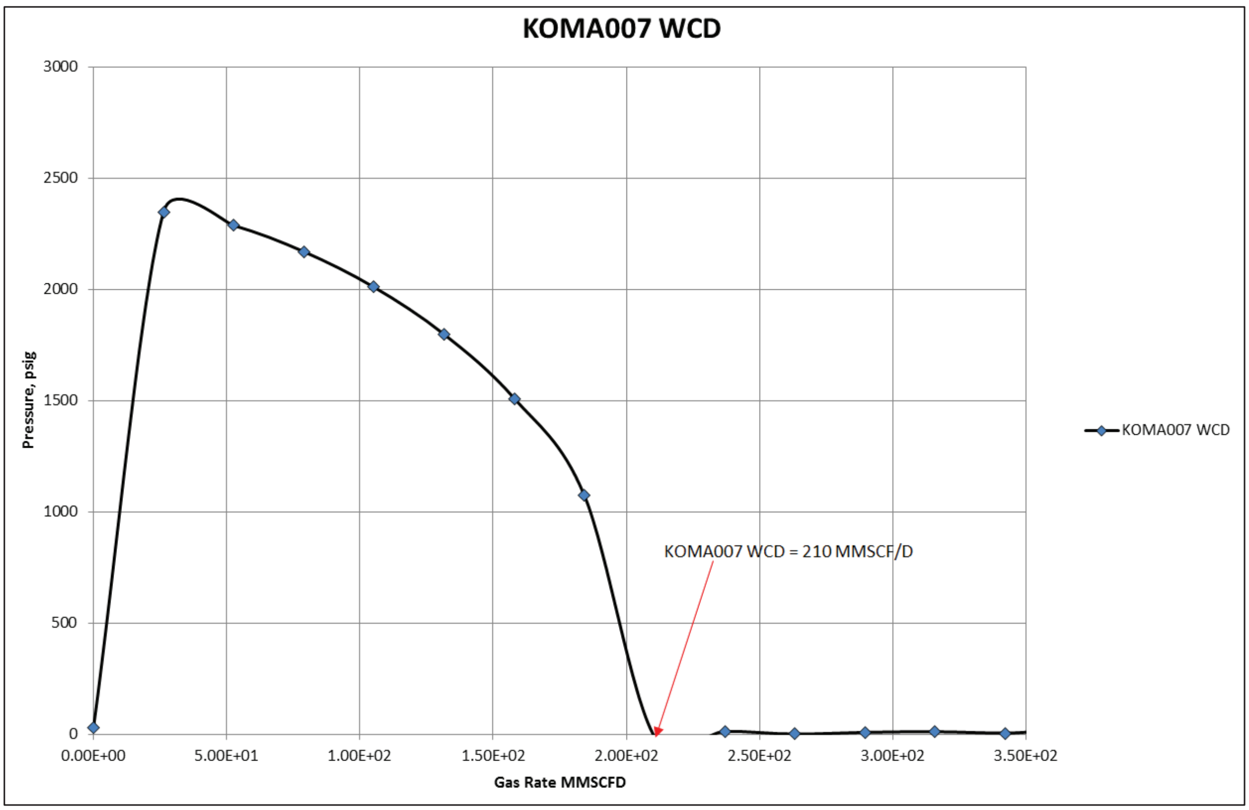
APPENDIX 5: Top Depth Map of the KOMA-007 D7000X sand.



APPENDIX 6: Cross section along KOMA-007 well path



APPENDIX 7: Worst Case Discharge Plot



APPENDIX 8: H2S Prediction

THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOROAMA-008 WELL CLEAN-UP/TEST PROPOSAL

September 2016

Well No	KOROAMA-008
Reservoir	KOROAMA-008 (E9000X and F1000X)
Estimated Duration	10 days
Cost	$2,238,293.41

Document Number:	SPDC-2016-09-00000038	Contributors:	Adebayo Adejoke (PT) Nnadi Magnus (RE) Esharegharan Ovoke (PG) David Olayinka (PP) Emmanuel Okolomma (CWI)
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1.0 BACKGROUND

KOROAMA – 008

Koroama-008 is a gas development well that was drilled to provide drainage points on the E9000X and F1000X reservoirs and develop a total of 67.8 Bscf of gas and 1.9 MMstb of condensate at an initial combined production potential of 70 MMscf/d.

Table 1: Koroama 008 Volumes

Reservoir	Gas UR (Bscf) Base case	Condensate UR (MMbbl) Base case	Gas Rate (MMscf/day)
E9000	11.4	0.3	40
F1000	56.4	1.6	30

The well was spudded on the 6th of November 2013, drilled to a TD of 12,113 ftah (10,985 ftss), and completion operation ended on 23rd of June 2016.

The well penetrated the E9000 and F1000 sands at 10,690 ftss and 10,913 ftss, encountering a gross gas column of 62 ft and 72 ft tvd respectively. It was completed as a Single String Dual (SSD) SMART gas producer on the E9000X and F1000X gas reservoirs with both sands to be commingled through the 3-1/2" x 5-1/2" 13Cr tubing equipped with Interval Control Valves (ICVs), dual-sensor Permanent Down Hole Gauges (PDHGs), feed-through swell packer, HF1 production packer and Tubing Retrievable Surface-Controlled Subsurface Safety Valve (TRSCSSSV). Expandable Sand Screens (ESSs) combined with blanks and swell-able packers (for zonal isolation) were installed across the sand face for effective sand control.

Production started in the F1000 reservoir in July 2013 with Koroama-003 well. As at May 2016, the cumulative production from the reservoir was 59.35 Bscf. There is No production from the E9000X reservoir.

It is proposed to clean up the E9000X and F1000X intervals to 40 MMscf/d and 30 MMscf/d respectively to remove drilling and completion debris and fluids. Multi-rate test will be conducted a rate of 40 MMscf/d on the E9000X and 30 MMscf/d on the F1000X intervals.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to get rid of mud filter cake, completion fluids and debris.
- Confirm zonal isolation from pressure profiles of the dual PDHGs
- Conduct multi-rate test per interval for the wells:
    - KOMA008 (40 MMscf/d on E9000X and 30 MMscf/d on F1000X)
- To validate the promised well potential of about 70 MMscf for KOMA008
- Conduct Build up test to obtain data required for reservoir characterization

1.2 Justification

The well's objective is to provide gas to the Gbaran CPF as part of the wells delivering gas to the NLNG T1 – T6. The cleanup is required to remove 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. Results from the MRT will be used in updating the well models and evaluating the potential in combined production mode.

1.3 Work Summary

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

- Clean-up F1000X interval
- Clean-up E9000X interval
- Carry out MRT on F1000X interval
- Carry out MRT on E9000X interval

2.0 WELL CLEAN-UP DESIGN

Solids free oil based mud was used at the sand face for the lower completion. During the clean-up operation, a specially formulated oil mud breaker solvent system will be pumped through the ICV openings to dissolve the POBM in the tubing casing annulus. The treatment fluid would be injected to contact the ESS and dislodge any filter cake and mud left behind. All injected fluids would be flowed back after required soaking time is observed. The flow back well effluent (completion brine) will be evacuated with vacuum truck to the Gbaran Central Processing Facility (CPF) for disposal.

During the clean-up operation, the well should be flowed long enough to allow sufficient time to offload well on each bean while monitoring sand production (using sand monitors e.g clamp-on). After every bean change, sand trap will be purged for inspection of well effluents. If there is significant sand production (>0.5 lbs/MMscf), flow will be stopped pending review of operation. See Appendix 3D for detailed contingency plan. All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

2.1 Clean-Up/Test Requirements

- Liquid knock out vessel
- Well Test Skid equipped with sand traps
- Clamp on sand monitors
- Surface Tanks - to receive initial well effluent (completion and kill brine, mud etc.)
- Coiled Tubing/Nitrogen
- Slick line
- Flare head burner (Compulsory requirement)
- Mono- Ethyl Glycol (To mitigate hydrates at low rates)

2.2 Well Clean-Up Operation

The well cleanup operation will follow the scope stated below. Clean-up parameters are not predictable; however, the Tables 2 and 3 below give a fair guide. Appendix 2 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 WGR ca. 0 bbl/MMscf is achieved. Thereafter, shut-in the well for 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

2.3 Clean-Up Work Scope

KOROAMA – 008

- RIH CT, wash and displace tubing string to treatment fluid
- Cycle open F1000X ICV at 11,951 ftah and pump treatment fluid to dissolve POBM in tubing casing annulus as well as POBM filter cake in sand face.
- Cycle close F1000X ICV and allow treatment fluid to soak for required period.
- Cycle open E9000X ICV at11,420 ftah and pump treatment fluid to dissolve POBM in tubing casing annulus as well as POBM filter cake in sand face.
- Cycle close E9000X ICV and allow treatment fluid to soak for required period.

- Clean-up F1000X interval as per program (Table 2), pump nitrogen to lift the well if it does not flow naturally. Cycle close F1000X ICV after clean up.
- Clean-up E9000X interval as per program (Table 3), pump nitrogen to lift the well if it does not flow naturally. Cycle close E9000X ICV after clean up.

NOTE:

- Initial opening of well must be during daylight.
- Bean-up must be done gradually.
- 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, not exceeding a specified maximum gas rate. Well is properly cleaned-up when at least 80% of expected FTHP is achieved on any bean shown in Tables 2 and 3 below
- All temporary pipe connections must be properly secured and tested to expected pressures

KOMA008 Clean-up: F1000X

The clean-up of F1000X interval will commence from choke 22/64th, however the interval will be gradually beaned up in steps. Due to unexpanded ESS on this interval, a 10 minute flow period should be observed at each change in variable bean size to allow for sand production monitoring.

Table 2: KOMA008 F1000X Well Clean-up Guide

Expected Bean Size (1/64th)	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
22	10	0	2964	2*	6	Take sample, check for sand, measure FTHP
28	15	0	2945	2*	10	Take sample, check for sand, measure FTHP
32	20	0	2952	2*	13	Take sample, check for sand, measure FTHP
40	30	0	2906	4**	19	Take sample, check for sand, measure FTHP

* Stabilized flow on each bean
**Recommended flow period however well to be flowed on this bean until clean-up criteria is achieved.

Clean up criteria

Stabilized THP for 1 hour
BSW </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 psia

KOMA008 Clean-up: E9000X

The clean-up of E9000X interval will commence from choke 22/64th (Note bean should be very gradually increased for each change in bean size).

Table 3: KOMA008 E9000X Well Clean-up Guide

Expected Bean Size (1/64th)	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
22	10	0	3261	2*	60	Take sample, check for sand, measure FTHP
34	20	0	3168	2*	146	Take sample, check for sand, measure FTHP
40	30	0	3088	2*	243	Take sample, check for sand, measure FTHP
48	40	0	2944	4**	286	Take sample, check for sand, measure FTHP

* Stabilized flow on each bean
**Recommended flow period however well to be flowed on this bean until clean-up criteria is achieved.

Clean up criteria
Stabilized THP for 1 hour
BSW </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 psia

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

3.1 Initial Build-up Period

- Close each interval with the ICV for 24 hours for an initial build-up after well clean-up to allow for reservoir stabilization prior to multirate test. Record CITHP.
- Monitor surface read-out of SBHP for pressure stabilization before proceeding to MRT. Also KOMA003T which is producing from the F1000X reservoir should be shut-in to minimize interference.

3.2 Flowing Period

- Open up each interval to carry out multi-rate test. See Tables 4 and 5 below for guide on production parameters during the flow period, for each interval.

Table 4: KOMA008 F1000X MRT data

Expected Bean Size (fixed choke) (1/64th	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
22	10	0	2964	4	6	Take sample, check for sand, measure FTHP
28	15	0	2945	4	10	Take sample, check for sand, measure FTHP
32	20	0	2952	4	13	Take sample, check for sand, measure FTHP
40	30	0	2906	4	19	Take sample, check for sand, measure FTHP
-	0	-	-	24	0	Build-up

Table 5: KOMA008 E9000X MRT data

Expected Bean Size (fixed choke) (1/64th	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
22	10	0	3261	4	60	Take sample, check for sand, measure FTHP
34	20	0	3168	4	146	Take sample, check for sand, measure FTHP
40	30	0	3088	4	243	Take sample, check for sand, measure FTHP
48	40	0	2944	4	286	Take sample, check for sand, measure FTHP
-	0	0	-	24	0	Build-up

Bean up should be carried out when flow stabilizes and FTHP & BSW are stable for at least 1 hour.

- 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 build-up as specified in the Table 7 (Final Buildup duration determined from section 4.0).
- The pressures will be recorded with the PDHG.

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 models were built based on the well and reservoir data as detailed in Table 6. Pressure simulations were generated based on the wells intervals potentials of Tables 4 and 5. 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 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 6: Test Design Input Parameters

Parameter	KOMA008 (F1000)	KOMA008 (E9000)	Comment
a. Reservoir Data			
Pay Zone Thickness (ft)	115	62	Based on well data
Average Formation Porosity (frac)	0.24	0.21	Based on well data
Formation Compressibility (1/psi)	3.32E-06	3.32E-06	Estimated using Hall correlation.
Reservoir Pressure (psia)	4027	469	RCI/MBAL
Reservoir Temperature (F)	185	172	Based on well data
Reservoir Permeability (mD)	1280	613	Mean reservoir permeability calculated from FZI analysis using logs acquired from Wells
b. Well Data			
Well Orientation	Vertical	Vertical	
Well Radius (ft)	0.35	0.35	Hole size
Well bore Storage (WBS) Coefficient (bbl/psi)	0.059	0.050	Estimated using the total volume of fluids expected in the wellbore if the shut-in was carried out at the surface.
c. Fluid data			
Fluid Type	Gas	Gas	
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model	Based on structure		
Modelling Approach	Numerical		To capture complexities (fault count and orientation) in the reservoir structure.

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 values derived from logs have been used in the design.

BOUNDARY MODEL:

The TOP structure Map (Appendix 5) was digitized and used in the design. A review of the structure shows that the reservoir is fault/dip bounded. The respective reservoir configurations formed the basis for digitizing of each the reservoir maps. There were generally no intra reservoir faults, the outer boundary to be seen by the well pressure responses will likely be the boundary faults.

SKIN:

No data was available to evaluate the possible skin values that may exist in reality. However actual skin values were obtained from MRT of producing wells in the field.

WELLBORE STORAGE:

Wellbore storage coefficients were estimated for surface shut in at the wellhead. The well test design was carried out using these well bore storage values. 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, PDHGs are available in the wells and the production intervals would be shut in at the sand face using ICV. As a result the wellbore storage is expected to be minimal.

Given the above, the scenarios as shown in Figure 1 and 2 below were simulated and the generated pressure responses analyzed.

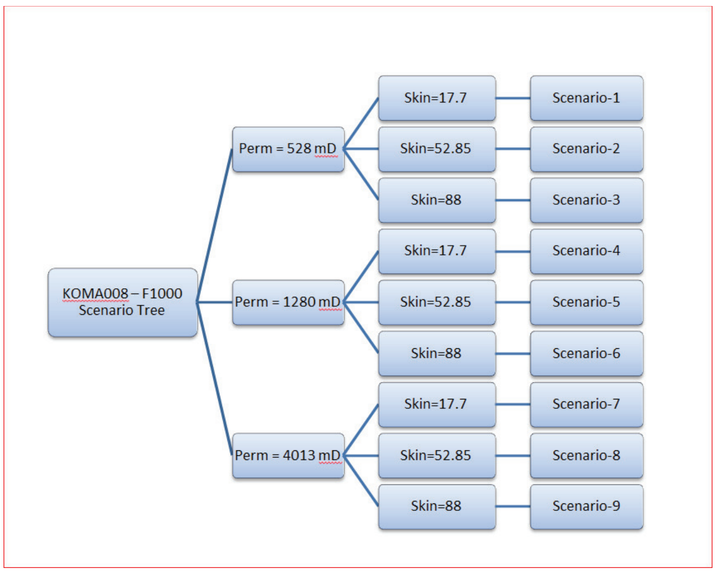


Figure 1: KOMA008 (F1000X) Scenarios

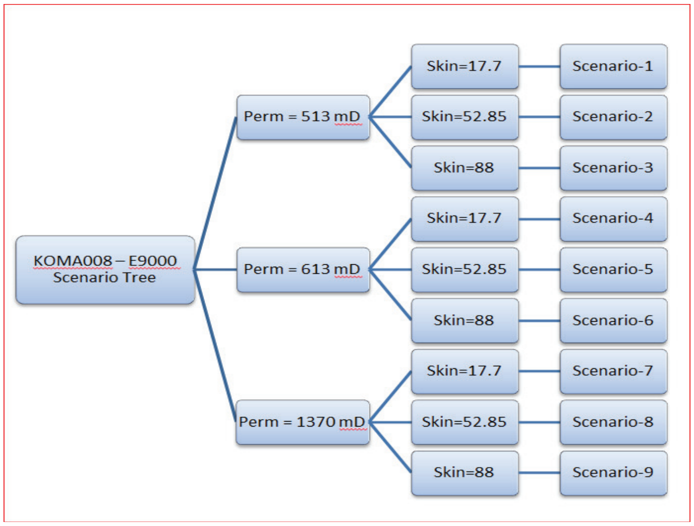


Figure 2: KOMA008 (E9000X) Scenarios

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 (see Tables 4 and 5).

The derivative plots for the different scenarios can be seen in figures 3 and 4. From the figures, the following can be deduced

1. The variation in the skin values will not result in any significant distortion to the expected reservoir behaviour and no impact on the time to the outer boundary from the test.
2. The late time pressure response indicated an outer boundary primarily dominated by mainly parallel fault boundary effect for various permeability cases.
3. The estimated build-up duration for KOMA008 intervals are about 24 hours each. A summary of the optimal durations for the production interval build-up are shown in Table 7.

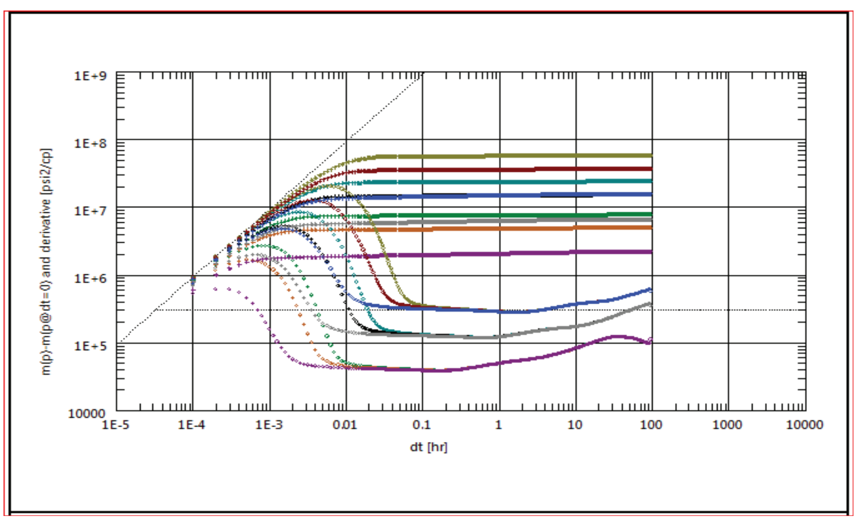


Figure 3: Log-Log plot for KOMA008 (F1000X) Sensitivities

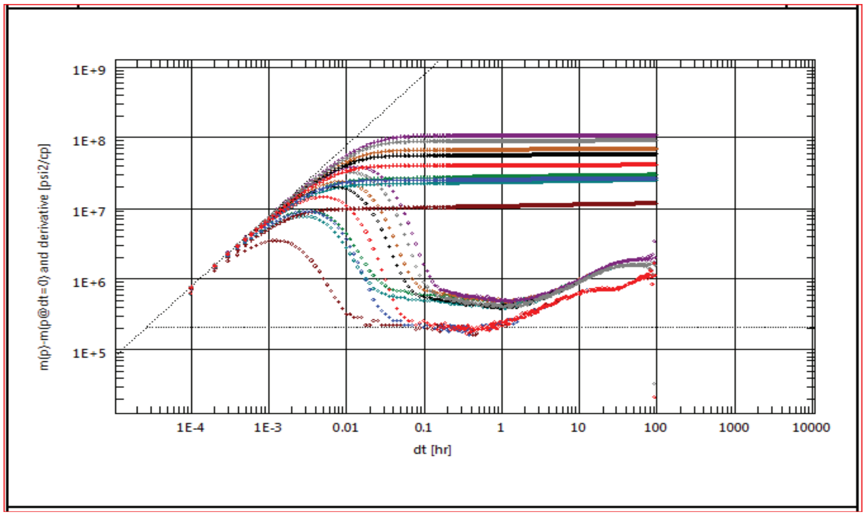


Figure 4: Log-Log plot for KOMA008 (E9000) Sensitivities

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 as detailed in the table below.

Table 7: Optimal Test Timing

Scenario	Initial Buildup (Pre Test) Hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
KOMA008: F1000	24	4	4	4	4	24	64
KOMA008: E9000	24	4	4	4	4	24	64

5.0 MRT WORKSCOPE SUMMARY

The summary of the MRT work scope for each interval is given as follows:

- After well clean-up, shut-in interval for 24 hours for initial reservoir stabilization
- Open up interval and conduct Multirate test (Tables 4 and 5)
- Shut in well for specified number of hours for final build-up test (Table 7).
- Secure well.
- RD equipment.

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.

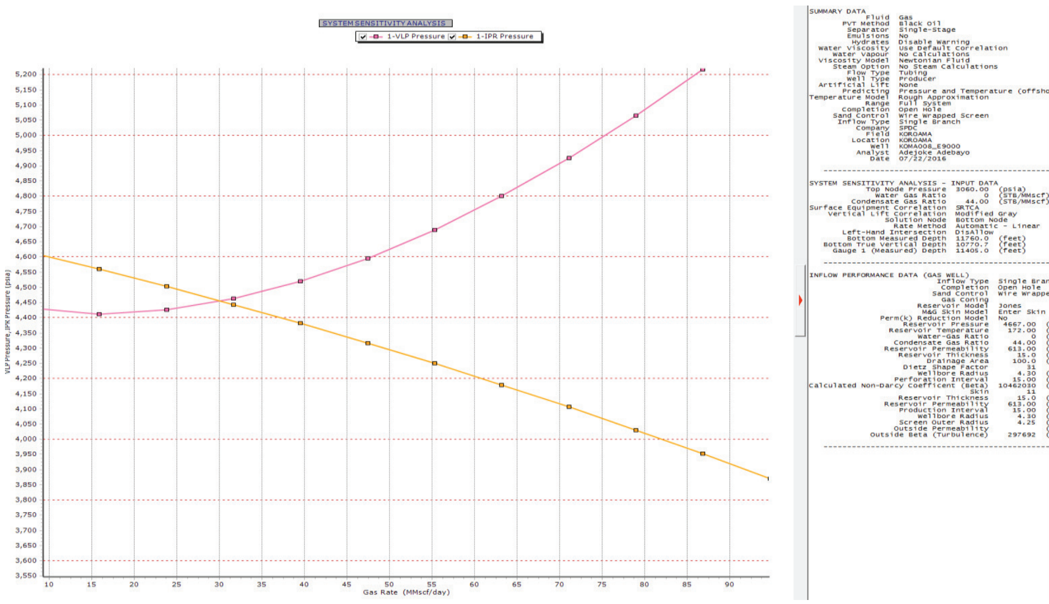
APPENDIX 1: RESERVOIR & COMPLETION DATA

KOROAMA – 008 Reservoir and Completions

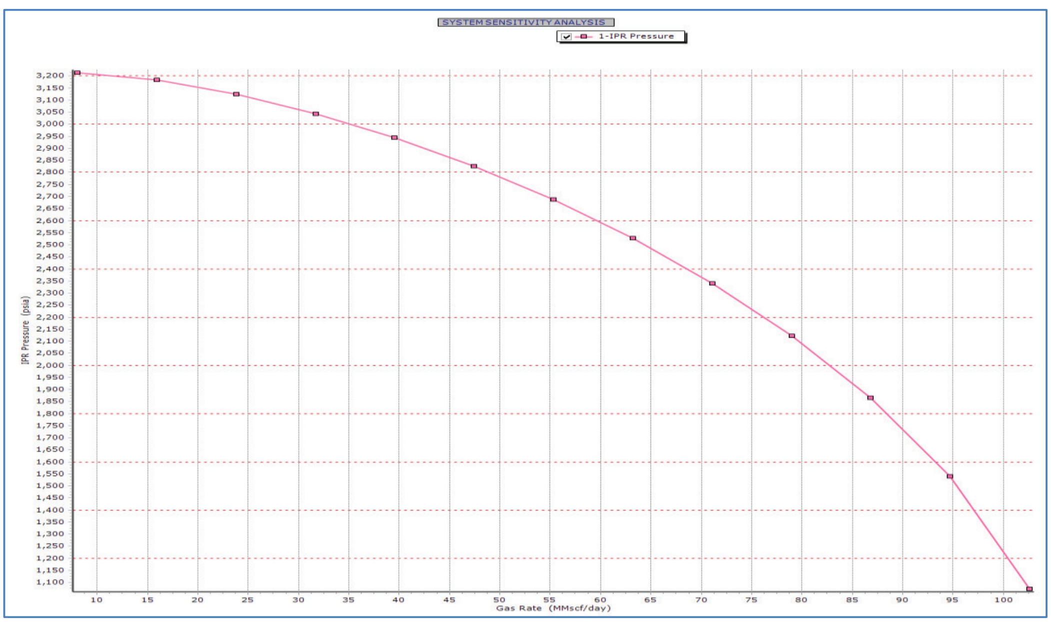
Target Reservoir	E9000X	F1000X
1. Casing size and Type	9-$^{5}/_{8}$''/Production casing	
2. Casing Setting Depth (ftah)	11,752	
3. Top of Sand [ftss/ftah]	10,696/ 11,748	10,913 / 12,204
4. Gross Sand Thickness (Gross) penetrated by Koroama-008(ft tv)	62	72
5. Well TD (ftss/ftah)	10,985/ 12,113	
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	10,700 – 10,715 11,760 – 11,780	10,920 – 10,982 12,033 – 12,109
7. Length of Completion Interval (ftah)	20	76
8. a) Top of competent cement (ftah) b) Source of data	6,486 CBL	
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 37.770 @ 8,259	
10. Deviation at completion zone	37.37	
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)	4,696 10,793 4,696 (KOMA010 RCI) 172 10,690 4,667	4,827 11,014 4,599 (MBAL) 185 10,913 4,117
12. Did RCI indicate abnormal pressures?	No	No
13. Pressure gradient @ top of sand (psi/ft)	0.437	0.377
14. a) Is the reservoir fully gas-bearing?	No	Yes
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC(ft)	Yes 10,745 (GWC) N/A	No 11,108 (GDT) 11,110 (WUT) N/A
16. Distance between lowest completion interval and estimated GWC in well / reservoir (ftss), ref GDT	30	N/A
17. Gas S.G. (air=1)	0.74	0.66
18. Condensate gravity (API)	45.9	44
19. Expected FTHP (psia)	3150	2893
20. Expected CITHP (psia)	3210	2940
21. Expected Drawdown (psi)	139	20
22. Is sand exclusion installed?	Yes OHESS	Yes OHESS

APPENDIX 2: WELL PERFORMANCE PLOTS

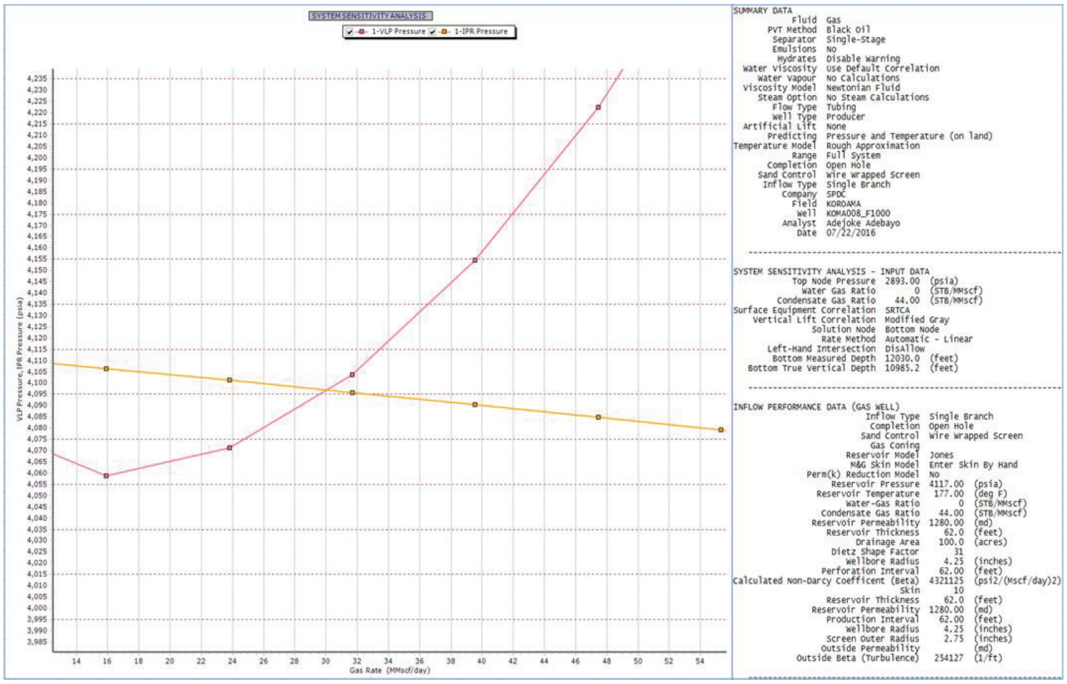
KOROAMA 008 E9000 MRT Well Performance



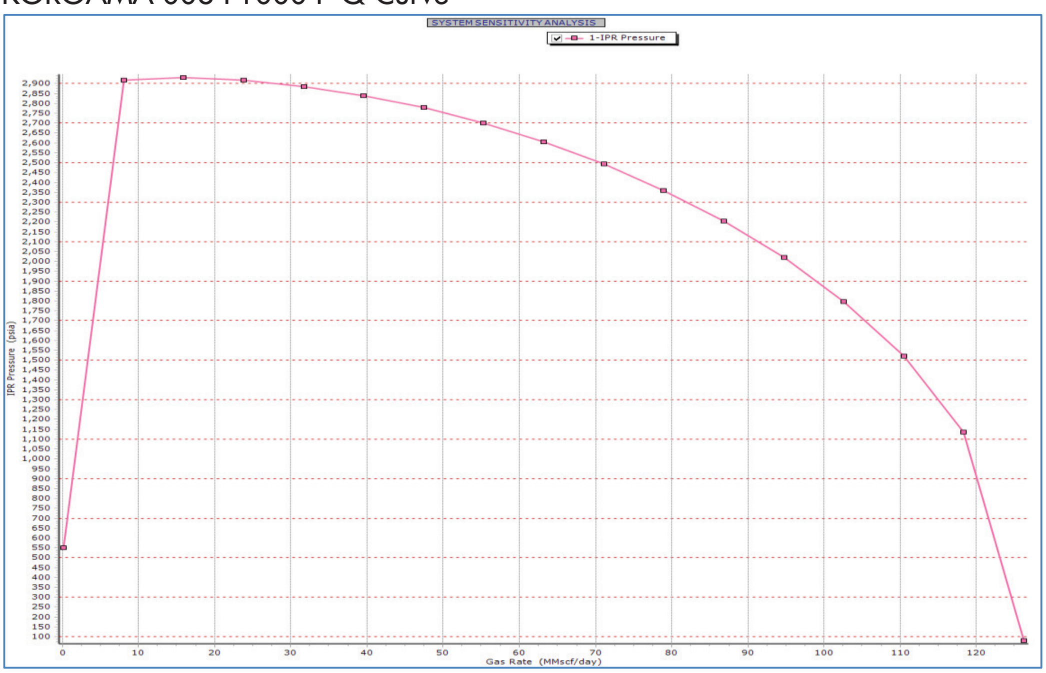
KOROAMA 008 E9000 P-Q Curve



KOROAMA 008 F1000 MRT Well Performance



KOROAMA 008 F1000 P-Q Curve



APPENDIX 3A: CRITICAL WELL TEST OPERATIONS RISKS/MITIGATION

Risk/Description	Consequence	Likelihood / Impact (L/M/H)	Mitigation
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	L/M	Ensure the dimensions of the tools to be RIH are appropriately sized for 3-1/2" tubing accessories/profiles ID
Emergency to spill, loss of containment	Loss of order, injury, fatality, loss of equipment	L/H	Ensure presence of 3-barriers at all time during clean-up/MRT operations. Also ensure all HAZID actions are closed-out prior to commencing operation
Hydrocarbon under pressure from kick or blowout	Explosion, loss of containment, injury, fatality and environmental pollution	L/H	Check integrity of the valves on the wellhead and WRSCSSV are integrity. Install surface readout gauges to monitor pressures and ensure BOP for the coil tubing unit is fully functional
Corrosive cleaning chemicals	Corrosion, environmental contamination.	L/H	Confirm that Nitrogen for lifting is tolerated by tubing/casing material.

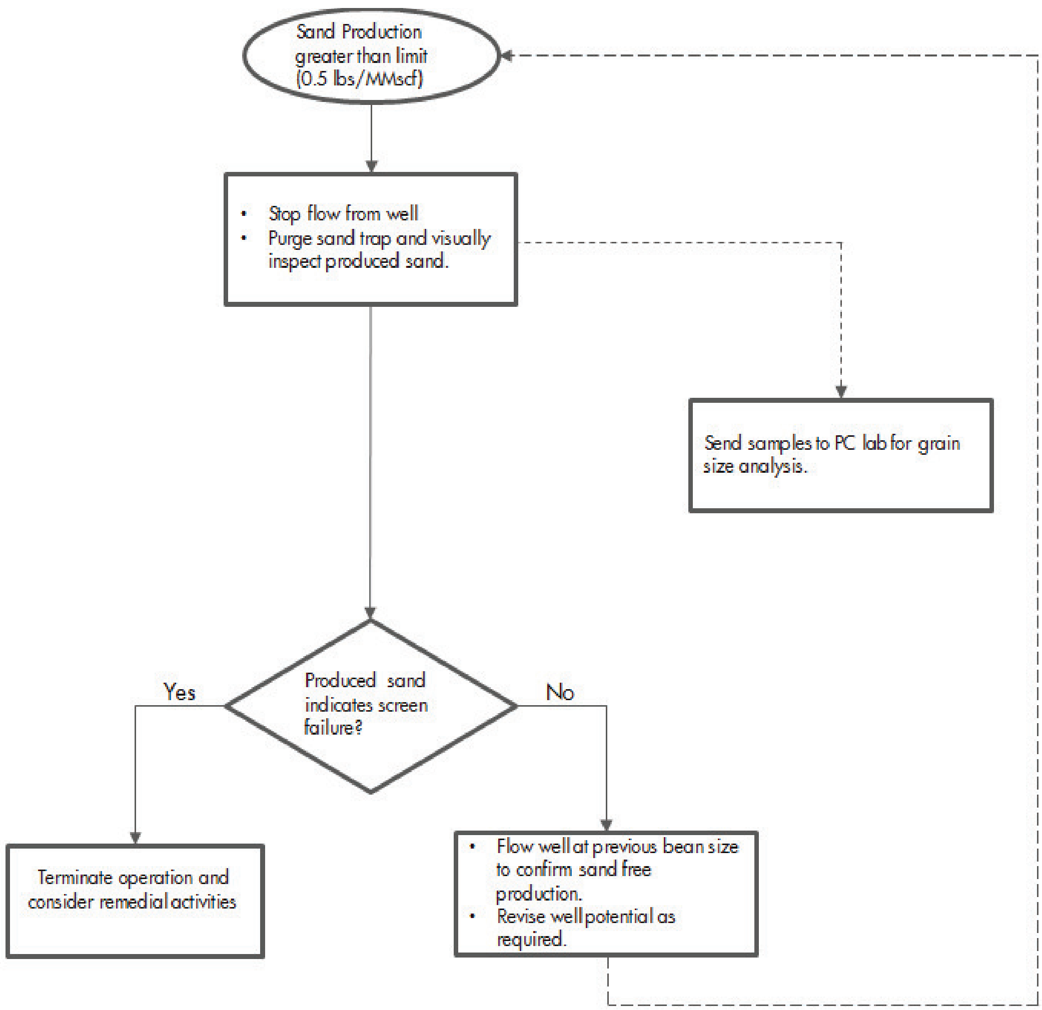
APPENDIX 3B: GAS WELL TEST RISKS/MITIGATION

Risk	Consequence	Mitigation
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Glycol will be injected at low gas rates to combat possible hydrate formation. At gas high rates, tubing temperatures are high enough to combat hydrate.
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.	13%Cr, completion material eliminates the need for corrosion inhibitor injection. Also wellhead have stainless steel clads.
Fire Source	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.
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 equipment.	Presence of 3-barrier containment Emergency Shut 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

APPENDIX 3C: DEP Table

DEP	Title	Remarks	Accountable DP
25.80.10.10-Gen	Formation Pore Pressure, Fracture Gradient (PP/FG) and Borehole Stability Prediction.	No drilling activity would be carried out during the operation	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 were done prior to drilling.	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 for KOMA008 is estimated at 700 MMscf/d	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 done as an input to the Well proposal. Well has been completed with OHESS installed for sand control. Sand monitoring would be done during the well test.	PT

APPENDIX 3D: Sand production contingency plan



APPENDIX 4: Koroama-008 Final Completion Status Diagram

KOROAMA 8 (EX-TBUV-3) COMPLETIONS SCHEMATIC

CASING

SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn	
24"	Stove Pipe		3500	Driven		Stovepipe
13-3/8"	K55	68	5,800	Class G	SLX	Surf Csg
9-5/8"	N80	47	8,240	Class G	SLX	Prod Csg

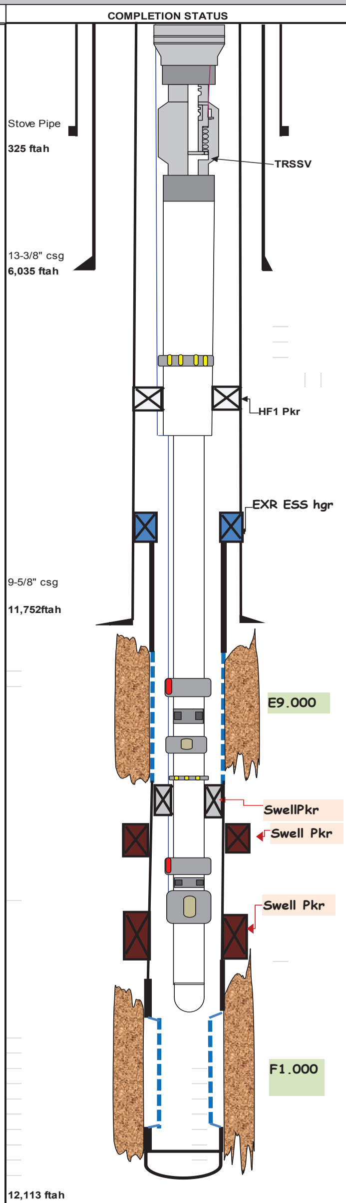
WELLHEAD (Surface Metal Seal 6 ported System)

ITEM	TYPE	SIZE	WP
XMAS TREE	Compact	7-1/16" x 11" Flange block x 4-1/16" outlet	5,000 psi
TREE CAP	Cameron	7-1/16" c/w 4-1/16" Bore	5,000 psi
GATE VALVE	Cameron	7-1/16" c/w 4-1/16" Bore	5,000 psi
ACTUATOR VALVE	Cameron	7-1/16" c/w 4-1/16" Bore	5,000 psi
TUBING HANGER	Cameron	7-1/2" 6 Single Ported w/CL & PDHG Prep	5,000 psi
STARTER HEAD (CHH)	Cameron	13-3/8 x 13-5/8"	5000 psi
WELLHEAD HOUSING	Adapter spool	13-5/8" X 13-3/8"	5,000 psi
GATE VALVE	Cameron	2-1/16" c/w 2.060" Bore	5,000 psi

TUBING

STRING	SIZE	WT.	GRAD.	TYPE			HOLE	DESCRIPTION	RESERVOIR
					MAX Deviation:	37.9°		CHESS/SMART Completions	E9.000 & F1.000
					RT - Top XMT =				
	3-1/2"	9.3#	N80	HCS	DFE (RT - Compact Housing)= 28.80ft				
	5-1/2"	17#	N80	HCS	XMT =	Drill-in Fluid Type / Properties		POBM (10.0ppg) 0.52psi/ft	Max inclination 37.9deg @ 6,268ftah
						Completion Fluid Type / Properties:		KCl Brine (0.48 psi/ft)	
						Gas Pressure Gradient / Pressure:		0.705 sg/0.45psi/ft	

SAND | **COMPLETION STATUS**

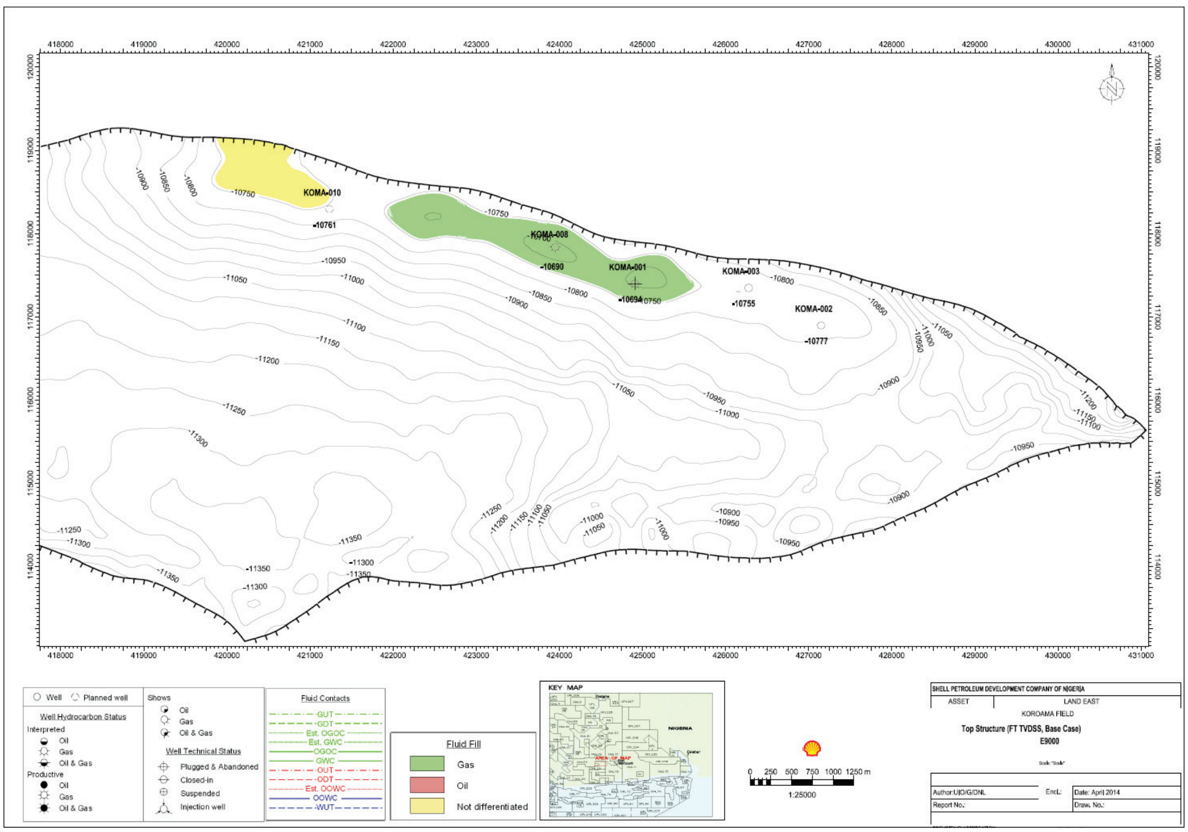


Top Depth	Length	O.D.	I.D.	DESCRIPTION
	34.66			Elevation
34.66	1.01	13.38	6.184	7" x 13-3/8" 5k psi prep for 6 ported Tubing Hanger
35.67	0.82	7.000	4.892	Crossover sub 7" 29# X5-1/2" 17# L-80 Hydri, 563 pin x pin
36.49	6.31	6.050	4.892	Pup Joint; 5-1/2" 17# L-80 Hydri,563 box x pin
42.80	105.00	6.050	4.892	**3 Joints**; 5-1/2" 17# Hydril,563 N-80 tubing
147.80	6.49	6.050	4.892	Pup Joint; 5-1/2" 17# L-80 Hydri, 563 box x pin
154.29	5.71	6.083	4.840	Flow Coupling, 5-1/2" 17" Hydril, 563 Box x Pin
160.00	8.31'	7.690	4.582	**TRSV; SP 5-1/2" x 4.562" Seal Bore. 7.69" Max OD 13Cr H2S Service. 5-1/2" 17# TSH563**
168.31	5.74'	6.083	4.840	Flow Coupling, 5-1/2" 20" Hydril 563 Box x Pin
174.05	3.98'	6.050	4.892	Pup Joint; 5-1/2" 13Cr 20# FJE box x pin
178.03	11,185.69	6.050	4.892	295 Joints; 5-1/2" 20# 13Cr L-80 FJE Bear tubing & 2jts H563
11,363.72	10.25	6.050	4.892	5 1/2" Pup Joint TSH 563 box x pin
11,373.97	2.01	6.050	3.812	Adapter Sub; 5-1/2" 17# TSH 563 Box x 4-1/2 12.6#Vam Top Pin
11,375.98	1.20	6.050	3.812	Adapter Sub, 5 1/2" 17# Vamtop Box X 4 1/2" Vamtop pin
11,377.18	15.02	8.440	3.812	**HF-1 Packer, 9 5/8" 47#, 5- 1/2" 17# VAM top Box x Pin.**
11,392.20	1.04	4.250	2.992	Adapter Sub; 4-1/2 12.6#Vam Top Box x 3-1/2" 9.3# TSH 563 Pin
11,393.24	6.10	4.250	2.992	Pup Joint Joint 3-1/2" 17# TSH 563 Pin x Pin,
11,399.34	3.95	4.250	2.992	Pup Joint 3-1/2" 9.3# TSH 563 Box x Pin,
11,403.29	1.20	4.250	2.992	Adapter Sub; 3-1/2 9.3# TSH 563 Box x3-1/2" 9.3# Hydril CS Pin
11,404.49	6.62	5.226	2.949	**Permanent Monitoring Gauge Integrations, 3 1/2 OD, 9.30 lb/ft TUBING WEIGHT**
11,411.11	1.14	4.250	2.992	Adapter Sub; 3-1/2 9.3# Hydril CS Box x 3-1/2" 9.3# TSH 563 Pin
11,412.25	1.38	3.970	2.750	**Landing Nipple ,2.813,R,13CR,3 1/2-9.20 TSH 563,Box x Pin**
11,413.63	4.06	4.250	2.992	Pup Joint 3-1/2" 9.3# TSH 563 Pin x Pin,
11,417.69	2.17'	4.250	2.992	Pup Joint 3-1/2" 9.3# TSH 563 Pin x Pin,
11,419.86	1.13'	4.250	2.992	Adapter Sub; 3-1/2" 9.3# TSH 563 Box x 3-1/2 9.3# Vam Top Pin
11,420.99	**11.25**	5.865	2.750	**VALVE, HS, 3-1/2,10.20 VAMTOP BOX, 3 1/2-10.20 VAMTOP PIN,**
11,432.24	1.13'	4.250	2.992	Adapter Sub; 3-1/2" 12.6# Vam Top Box Box x 3-1/2 9.3# TSH 563 Pin
11,433.37	3.98'	4.250	2.992	Pup Joint 3-1/2" 9.3# TSH 563 Box x Pin
11,437.35	375.05	4.250	2.992	**Tubing Joint, 3-1/2" 9.3# TSH 563 Box x Pin (12 Joints)**
11,812.40	6.05	4.250"	2.992"	Pup Joint 3-1/2" 9.3# TSH 563 Box x Pin
11,818.45	1.33	4.260"	2.915"	Adapter Sub;3-1/2 9.3# TSH 563 Box x 4-1/2" 12.6# Vam Top Pin
11,819.78	3.14	4.945"	3.958"	Pup Joint 4-1/2" 12.6# VamTop Box x Pin
11,822.92	**39.56**	**6.380"**	**3.958"**	**Halliburton FT Swell Packer 7 5/8 in., 24-29.7 lb/ft Weight Range Vam Top**
11,862.48	3.14	4.945"	3.958"	Pup Joint 4-1/2" 12.6# VamTop Box x Pin
11,865.62	1.24	4.250"	2.992"	Adapter Sub; 4-1/2 9.3# Vam Top Box x 3-1/2" 9.3# TSH 563 Pin
11,866.86	4.19	4.250"	2.992"	Pup Joint 3-1/2" 9.3# TSH 563 Box x Pin
11,871.05	62.45	3.915	2.920	**Tubing Joint, 3-1/2" 9.3# TSH 563 Box x Pin**
11,933.50	4.07'	4.250"	2.992"	Pup Joint Joint 3-1/2" 9.3# TSH 563 Pin x Pin,
11,937.57	1.21'	4.250"	2.992"	Adapter Sub; 3-1/2 9.3# TSH 563 Box x3-1/2" 9.3# Hydril CS Pin
11,938.78	**6.63**	**5.226"**	**2.949"**	**Permanent Monitoring Gauge Integrations, 3 1/2 OD, 9.30 lb/ft**
11,945.41	1.10'	4.250"	2.992"	Adapter Sub; 3-1/2 9.3# Hydril CS Box x 3-1/2" 9.3# TSH 563 Pin
11,946.51	1.91'	4.250"	2.992"	Pup Joint Joint 3-1/2" 9.3# TSH 563 Pin x Pin,
11,948.42	1.73	3.922	2.750	Pup Joint Joint 3-1/2" 9.3# TSH 563 Pin x Pin,
11,950.15	1.13	3.915	2.920	Adapter Sub; 3-1/2" 9.3# TSH 563 Box x 3-1/2 9.3# Vam Top Pin
11,951.28	**11.24**	**3.915**	**2.920**	**VALVE, HS, 3-1/2,10.20 VAMTOP BOX, 3 1/2-10.20 VAMTOP PIN,**
11,962.52	1.15	4.250	2.992	Adapter Sub; 3-1/2" 12.6# Vam Top Box Box x 3-1/2 9.3# TSH 563 Pin
11,963.67	3.78	5.865	2.992	Pup Joint Joint 3-1/2" 9.3# TSH 563 Pin x Pin,
11,967.45	6.32	4.250	2.992	Pup Joint 3-1/2" 9.3# TSH 563 Box x Pin
11,973.77	0.70	4.250	2.992	Bull Plug Assembly; 3-1/2" 9.3# TSH 563 Box x Pin, Alloy 80
11,974.47				**End of upper completion Tubing**
				LOWER COMPLETIONS ESS ASSY
11,540.88	5.17	8.130	7.375	**PBR**
11,546.05	**6.24**	**8.400**	6.800	**Cardium EXR 7-5/8" x 9-5/8 " Hanger**
11,552.29	9.76	7.625	6.875	Pup 7-5/8" 29.7# Vam FJL box x pin
11,562.05	189.77	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing (6jts)
11,751.82	5.74	7.625	6.875	Pup 7-5/8" 29.7# Vam FJL box x pin
11,757.56	2.90	8.681	6.805	5-1/2" Mark II ESS ETC, 230 micron with 7 5/8" 29.7# FJL box x MKII pin
11,760.46	**19.74**	**8.681**	**7.381**	**5-1/2" E.S.S Mark II, ESS 230 micron with ESS MKII box x pin**
11,780.20	3.21	8.681	6.805	5-1/2" Mark II ESS EBC, 230 micron with ESS MKII box x 7 5/8" 29.7# FJL pin
11,783.41	19.74	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing (**20ft pup**)
11,803.15	**18.74**	**8.681**	**6.640**	**7 5/8" 29.7# Hybrid Swell Packer with 7 5/8" 29.7# FJL box x pin**
11,821.89	189.78	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing (5jts)
12,011.67	**18.74**	**8.681**	**6.640**	**7 5/8" 29.7# Hybrid Swell Packer with 7 5/8" 29.7# FJL box x pin**
12,030.41	2.90	8.681	4.805	5-1/2" Mark II ESS ETC, 230 micron with 7 5/8" 29.7# FJL box x MKII pin
12,033.31	**75.32**	**8.681**	4.805	**5-1/2" E.S.S Mark II, ESS 230 micron with ESS MKII box x pin**
12,108.63	3.22	8.681	4.805	5-1/2" Mark II ESS EBC, 230 micron with ESS MKII box x 7 5/8" 29.7# FJL pin
12,111.85	1.15	7.625		7-5/8" Bull Nose with 7 5/8" 29.7# FJL box
12,113.00				

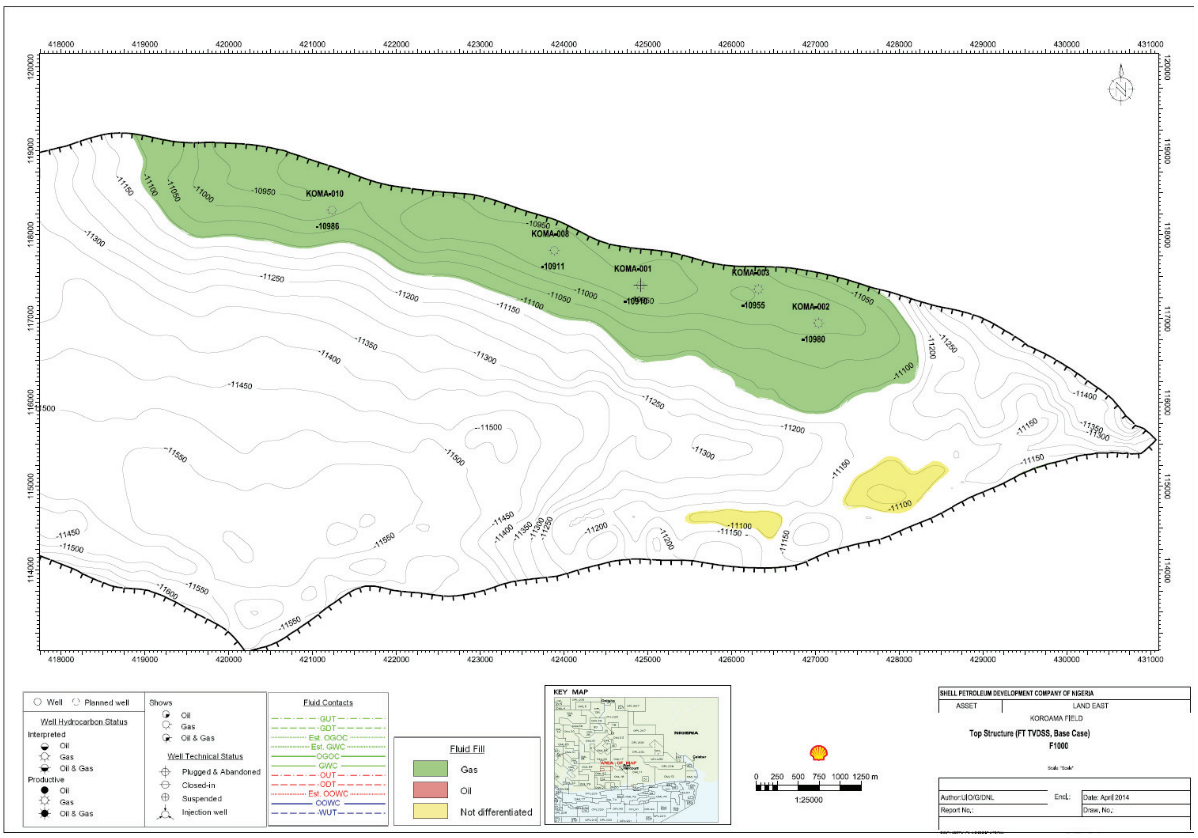
TD	12,113ftah	AUTHOR: Chuka Ofulue PTW/O/NG	DATE COMPLETED:	26-Jun-16

APPENDIX 5: Top Depth Map of the KOMA008 E9000X & F1000 sands

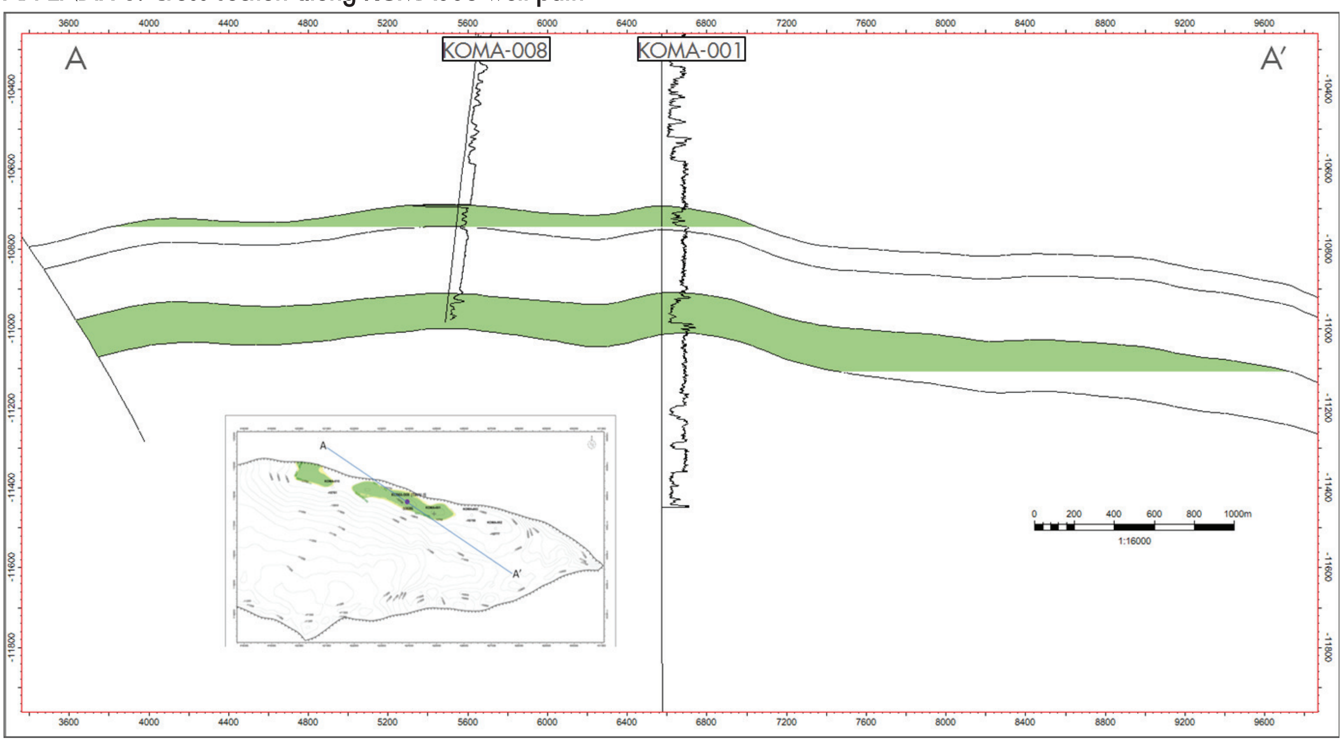
Top Depth Map of the KOMA008 E9000X sand



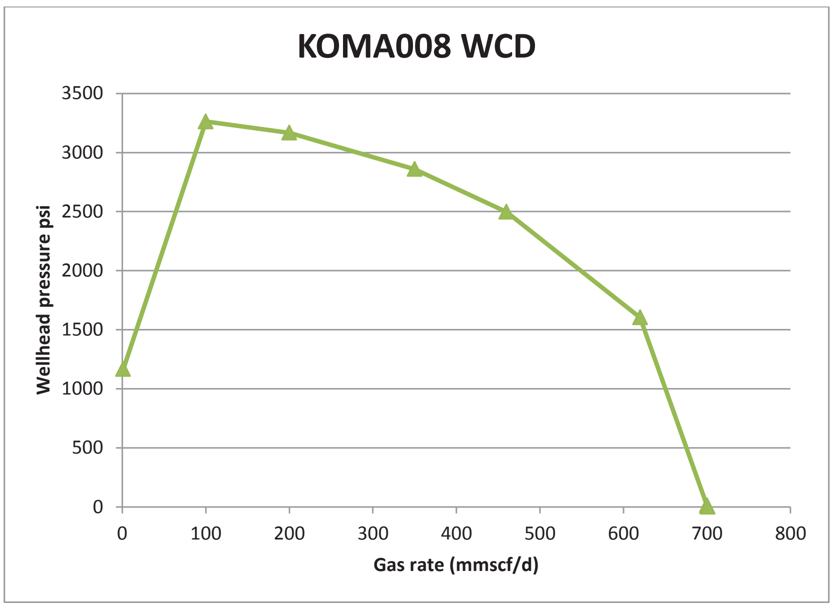
Top Depth Map of the KOMA008 F1000X sand



APPENDIX 6: Cross section along KOMA008 well path



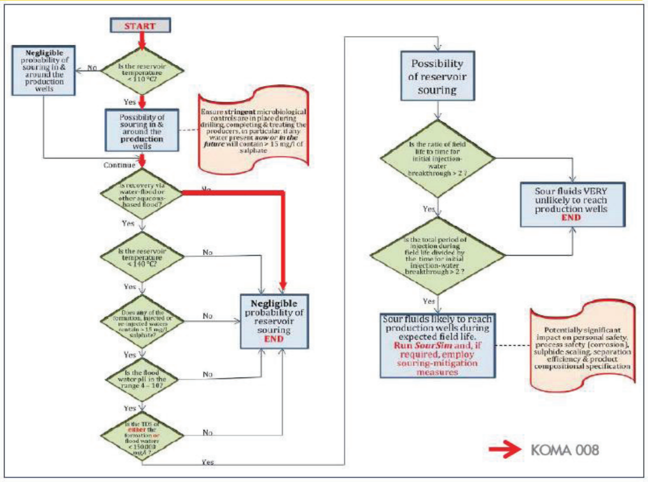
APPENDIX 7: Worst Case Discharge plot for KOMA008



APPENDIX 8: KOMA008 H_2S Prediction

KOMA 008 H_2S PREDICTION (E9000 AND F1000)

- KOMA008 is planned to be completed on E9000 and F1000.
- PVT data available for C9400, D6000, E7000 and F1000 reservoirs indicate no presence of H_2S.
- There is no PVT data available for E9000, however D7000, E1000 and F1000 reservoirs are currently producing with no H_2S production recorded.
- Production Operations and Production Chemist have not encountered H_2S in the Gbaran nodal area.
- Expected Reservoir Temperatures in E9000 and F1000 are 78ºC and 81ºC respectively
- No water-flood is planned for the field
- Hence, the souring potential is negligible.
- Gas testers and appropriate PPE's will be utilized during completion and well open up as additional mitigation.



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SPDC

Date: 5/5/2016

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THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOROAMA-009 WELL CLEAN-UP/TEST PROPOSAL

September 2016

Well No	KOROAMA-009
Reservoir	KOROAMA-009 (C9400X, D1000X, D6000X)
Estimated Duration	10 days
Cost	$2,782,743.16

Document Number:	SPDC-2016-09-00000039	Contributors:	Adebayo Adejoke (PT) Nnadi Magnus (RE) Nwabueze Chuks (PG) David Olayinka (PP) Emmanuel Okolomma (CWI)
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1.0 BACKGROUND

KOROAMA – 009

Koroama-009 is a gas development well that was drilled to provide a drainage point on the C9400X, D1000X and D6000X reservoirs and develop a total of 148 Bscf of gas and 1.0 MMstb of condensate at an initial combined production potential of about 92 MMscf/d.

Table 1: Koroama 009 Volumes

Reservoir	Gas UR (Bscf) Base case	Condensate UR (MMbbl) Base case	Gas Rate (MMscf/day)
C9400	51.6	0.5	30
D1000	14.4	0.1	30
D6000	81.9	0.4	32

The well was spudded on the 2nd of February 2014, drilled to a TD of 9,010 ftah (8,519 ftss), and completion operation ended on 12th of June 2016.

The well fully penetrated the C9400, D1000 and D6000 sands at 7,899 ftss, 8,033 ftss and 8,480 ftss, encountering a gross gas column of 20 ft, 27ft and 27 ft tvd respectively. It was completed as a Single String Multiple (SSM) SMART gas producer on the C9400X, D1000X and D6000X gas reservoirs with the three sands to be commingled through the 3-1/2" x 5-1/2" 13Cr tubing equipped with Interval Control Valves (ICVs), dual-sensor Permanent Down Hole Gauges (PDHGs), feed-through swell packers, HF1 production packer and Tubing Retrievable Surface-Controlled Subsurface Safety Valve (TRSCSSSV). Expandable Sand Screens (ESSs) combined with blanks and swell-able packers (for zonal isolation) were installed across the sand face for effective sand control.

No production has been recorded from any of the three reservoirs.

It is proposed to clean up the C9400X, D1000X and D6000X intervals to about 40 MMscf/d each to remove drilling and completion debris and fluids and also conduct Multi-rate test to about 40 MMscf/d on the each of the intervals.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to get rid of mud filter cake, completion fluids and debris.
- Confirm zonal isolation from pressure profiles of the dual PDHGs
- Conduct multi-rate test per interval for the wells:
    - KOMA009 (40 MMscf/d each for C9400X, D1000X and D6000X)
- To validate the promised well potential of about 90 MMscf/d for KOMA009.
- Conduct Build up test to obtain data required for reservoir characterization

1.2 Justification

The well's objective is to provide gas to the Gbaran CPF as part of the wells delivering gas to the NLNG T1 – T6. The cleanup is required to remove 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. Results from the MRT will be used in updating the well models and evaluating the potential in combined production mode.

1.3 Work Summary

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

- Clean-up D6000X interval
- Clean-up D1000X interval
- Clean-up C9400X interval
- Carry out MRT on D6000X interval
- Carry out MRT on D1000X interval
- Carry out MRT on C9400X interval

2.0 WELL CLEAN-UP DESIGN

Solids free oil based mud was used at the sand face for the lower completion. During the clean-up operation, a specially formulated oil mud breaker solvent system will be pumped through the ICV openings to dissolve the POBM in the tubing casing annulus. The treatment fluid would be injected to contact the ESS and dislodge any filter cake and mud left behind. All injected fluids would be flowed back after required soaking time is observed. The flow back well effluent (completion brine) will be evacuated with vacuum truck to the Gbaran Central Processing Facility (CPF) for disposal.

During the clean-up operation, the well should be flowed long enough to allow sufficient time to offload well on each bean while monitoring sand production (using sand monitors e.g clamp-on). After every bean change, sand trap will be purged for inspection of well effluents. If there is significant sand production (>0.5 lbs/MMscf), flow will be stopped pending review of operation. See Appendix 3D for detailed contingency plan. All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

2.1 Clean-Up/Test Requirements

- Liquid knock out vessel
- Well Test Skid equipped with sand traps
- Clamp on sand monitors
- Surface Tanks - to receive initial well effluent (completion and kill brine, mud etc.)
- Coiled Tubing/Nitrogen
- Slick line
- Flare head burner (Compulsory requirement)
- Mono- Ethyl Glycol (To mitigate hydrates at low rates)

2.2 Well Clean-Up Operation

The well cleanup operation will follow the scope stated below. Clean-up parameters are not predictable; however, the Tables 2 to 4 below give a fair guide. Appendix 2 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 WGR ca. 0 bbl/MMscf is achieved. Thereafter, shut-in the well for 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

2.3 Clean-Up Work Scope

KOROAMA – 009

- RIH CT, wash and displace tubing string to treatment fluid
- Cycle open D6000X ICV at 8930 ftah and pump treatment fluid to dissolve POBM in tubing casing annulus as well as POBM filter cake in sand face.
- Cycle close D6000X ICV and allow treatment fluid to soak for required period
- Cycle open D1000X ICV and pump treatment fluid to dissolve POBM in tubing casing annulus as well as POBM filter cake in sand face.

- Cycle close D1000X ICV and allow treatment fluid to soak for required period
- Cycle open C9400X ICV and pump treatment fluid to dissolve POBM in tubing casing annulus as well as POBM filter cake in sand face.
- Cycle close C94000X ICV and allow treatment fluid to soak for required period.
- Clean-up D6000X interval as per program (Table 2), pump nitrogen to lift the well if it does not flow naturally. Cycle close D6000X ICV after clean up.
- Clean-up D1000X interval as per program (Table 3), pump nitrogen to lift the well if it does not flow naturally. Cycle close D1000X ICV after clean up.
- Clean-up C9400X interval as per program (Table 4), pump nitrogen to lift the well if it does not flow naturally. Cycle close C9400X ICV after clean up.

NOTE:

- Initial opening of well must be during daylight.
- Bean-up must be done gradually.
- 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, not exceeding a specified maximum gas rate. Well is properly cleaned-up when at least 80% of expected FTHP is achieved on any bean shown in Tables 2 to 4 below
- All temporary pipe connections must be properly secured and tested to expected pressures

KOMA009 Clean-up: D6000X

The clean-up of D6000X interval will commence from choke 24/64th (Note bean should be very gradually increased for each change in bean size).

Table 2: KOMA009 D6000X Well Clean-up Guide

Expected Bean Size (1/64th)	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
24	10	0	3016	2*	6	Take sample, check for sand, measure FTHP
34	20	0	2989	2*	12	Take sample, check for sand, measure FTHP
42	30	0	2944	2*	19	Take sample, check for sand, measure FTHP
48*	40	0	2896	4*	24	Take sample, check for sand, measure FTHP

* Stabilized flow on each bean
**Recommended flow period however well to be flowed on this bean until clean-up criteria is achieved.

Clean up criteria

Stabilized THP for 1 hour
BSW of liquid sample </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 psia

KOMA009 Clean-up: D1000X

The clean-up of D1000X interval will commence from choke 24/64th (Note bean should be very gradually increased for each change in bean size).

Table 3: KOMA009 D1000X Well Clean-up Guide

Expected Bean Size (1/64th)	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
24	10	0	2888	2*	13	Take sample, check for sand, measure FTHP
34	20	0	2863	2*	27	Take sample, check for sand, measure FTHP
42	30	0	2825	2*	42	Take sample, check for sand, measure FTHP
50*	40	0	2766	4*	59	Take sample, check for sand, measure FTHP

* Stabilized flow on each bean
**Recommended flow period however well to be flowed on this bean until clean-up criteria is achieved.
Clean up criteria
Stabilized THP for 1 hour
BSW of liquid sample </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 psia

KOMA009 Clean-up: C9400X

The clean-up of C9400X interval will commence from choke 22/64th (Note bean should be very gradually increased for each change in bean size).

Table 4: KOMA009 C9400X Well Clean-up Guide

Expected Bean Size (1/64th)	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
24	10	0	2882	2*	20	Take sample, check for sand, measure FTHP
34	20	0	2854	2*	41	Take sample, check for sand, measure FTHP
42	30	0	2817	2*	64	Take sample, check for sand, measure FTHP
50*	40	0	2762	4**	91	Take sample, check for sand, measure FTHP

* Stabilized flow on each bean
**Recommended flow period however well to be flowed on this bean until clean-up criteria is achieved.
Clean up criteria
Stabilized THP for 1 hour
BSW of liquid sample </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 psia

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

3.1 Initial Build-up Period

- Close each interval with the ICV for 24 hours for an initial build-up after well clean-up to allow for reservoir stabilization prior to multirate test. Record CITHP.
- Monitor surface read-out of SBHP for pressure stabilization before proceeding to MRT.

3.2 Flowing Period

- Open up each interval to carry out multi-rate test. See Tables 5 to 7 below for guide on production parameters during the flow period, for each interval.

Table 5: KOMA009 D6000X MRT data

Expected Bean Size (fixed choke) (1/64th	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
24	10	0	3016	4	6	Take sample, check for sand, measure FTHP
34	20	0	2989	4	12	Take sample, check for sand, measure FTHP
42	30	0	2944	4	19	Take sample, check for sand, measure FTHP
48	40	0	2896	4	24	Take sample, check for sand, measure FTHP
-	0	0	-	24	0	Build-up

Table 6: KOMA009 D1000X MRT data

Expected Bean Size (fixed choke) (1/64th)	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
24	10	0	2888	4	13	Take sample, check for sand, measure FTHP
34	20	0	2863	4	27	Take sample, check for sand, measure FTHP
42	30	0	2825	4	42	Take sample, check for sand, measure FTHP
50	40	0	2766	4	59	Take sample, check for sand, measure FTHP
-	0	0	-	24	0	Build-up

Table 7: KOMA009 C9400X MRT data

Expected Bean Size (fixed choke) (1/64th)	Estimated Rate (MMscf/d)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
24	10	0	2882	4	20	Take sample, check for sand, measure FTHP
34	20	0	2854	4	41	Take sample, check for sand, measure FTHP
42	30	0	2817	4	64	Take sample, check for sand, measure FTHP
50	40	0	2762	4	91	Take sample, check for sand, measure FTHP
-	0	0	-	48	0	Build-up

Bean up should be carried out when flow stabilizes and FTHP & BSW are stable for at least 1 hour.

- 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 build-up as specified in the Tables 5 to 7 (Final Buildup duration determined from section 4.0).
- The pressures will be recorded with the PDHG.

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 models were built based on the well and reservoir data as detailed in Table 8. Pressure simulations were generated based on the wells intervals potentials of Tables 5 to 7. 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 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 8 below:

Table 8: Test Design Input Parameters.

Parameter	KOMA009 (D6000)	KOMA009 (D1000)	KOMA009 (C9400)	Comment
a. Reservoir Data				
Pay Zone Thickness (ft)	34	38	23	Based on well data
Average Formation Porosity (frac)	0.25	0.27	0.19	Based on well data
Formation Compressibility (1/psi)	3.32E-06	3.32E-06	3.32E-06	Estimated using Hall correlation.
Reservoir Pressure (psia)	3728	3530	3500	RCI/MBAL
Reservoir Temperature (F)	146	140	138	Based on well data
Reservoir Permeability (mD)	2582	1085	981	Mean reservoir permeability calculated from FZI analysis using logs acquired from Wells
b. Well Data				
Well Orientation	Vertical	Vertical	Vertical	
Well Radius (ft)	0.35	0.35	0.35	Hole size
Well bore Storage (WBS) Coefficient (bbl/psi)	0.043	0.048	0.044	Estimated using the total volume of fluids expected in the wellbore if the shut-in was carried out at the surface.
c. Fluid data				
Fluid Type	Gas	Gas	Gas	
d. Others				
Reservoir Model	Homogeneous			
Wellbore Model	Constant storage			
Boundary Model	Based on structure			
Modelling Approach	Numerical			To capture complexities (fault count and orientation) in the reservoir structure.

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 values derived from logs have been used in the design.

BOUNDARY MODEL:

The TOP structure Map (Appendix 5) was digitized and used in the design. A review of the structure shows that the reservoir is fault/dip bounded. The respective reservoir configurations formed the basis for digitizing of each the reservoir maps. There were generally no intra reservoir faults, the outer boundary to be seen by the well pressure responses will likely be the boundary faults.

SKIN:

No data was available to evaluate the possible skin values that may exist in reality. However actual skin values were obtained from MRT of producing wells in the field.

WELLBORE STORAGE:

Wellbore storage coefficients were estimated for surface shut in at the wellhead. The well test design was carried out using these well bore storage values. 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, PDHGs are available in the wells and the production intervals would be shut in at the sand face using ICV. As a result the wellbore storage is expected to be minimal.

Given the above, the scenarios as shown in Figure 1 to 3 below were simulated and the generated pressure responses analyzed.

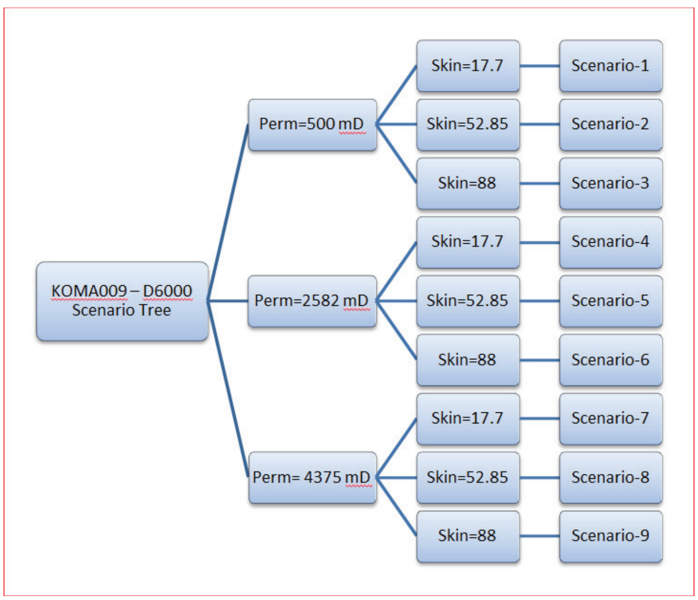


Figure 1: KOMA009 (D6000X) Scenarios

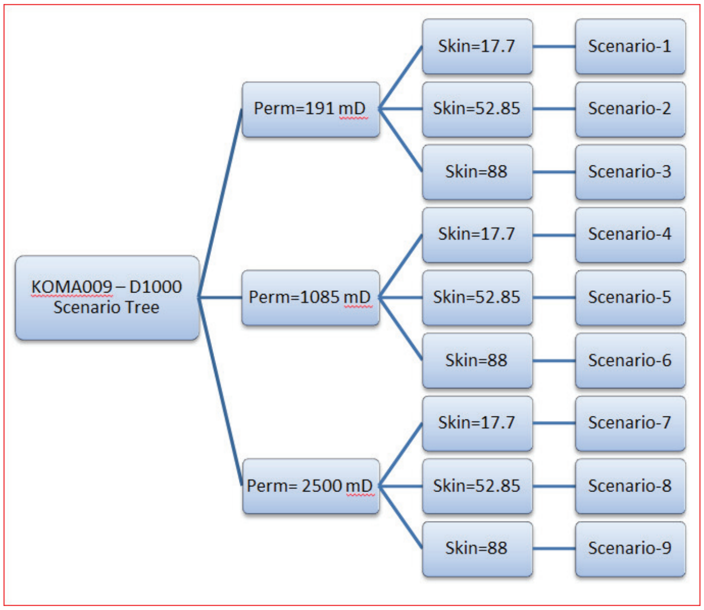


Figure 2: KOMA009 (D1000X) Scenarios

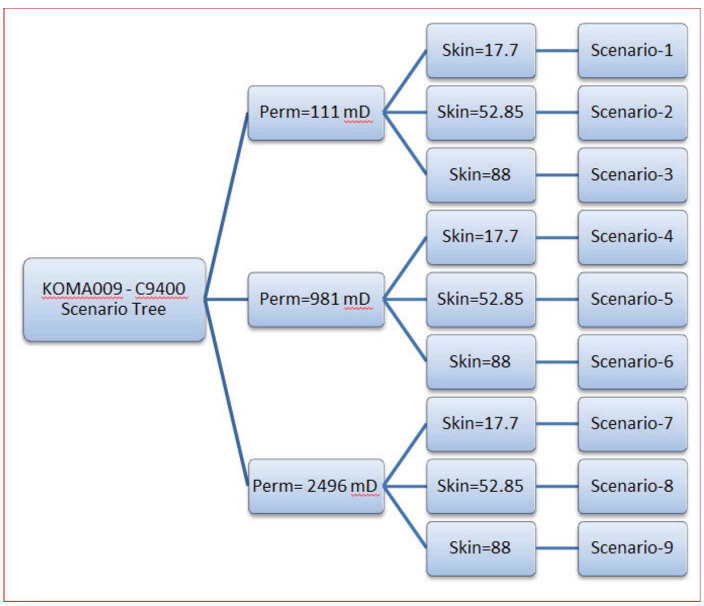


Figure 3: KOMA009 (C9400X) Scenarios

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 (see Tables 5 to 7).

The derivative plots for the different scenarios can be seen in figures 4 to 6. From the figures, the following can be deduced

1. The variation in the skin values will not result in any significant distortion to the expected reservoir behaviour and no impact on the time to the outer boundary from the test.
2. The late time pressure response indicated an outer boundary primarily dominated by mainly parallel fault boundary effect for various permeability cases.
3. The estimated build-up duration for KOMA009 intervals are about 48 hours each. A summary of the optimal durations for the production interval build-up are shown in Table 9.

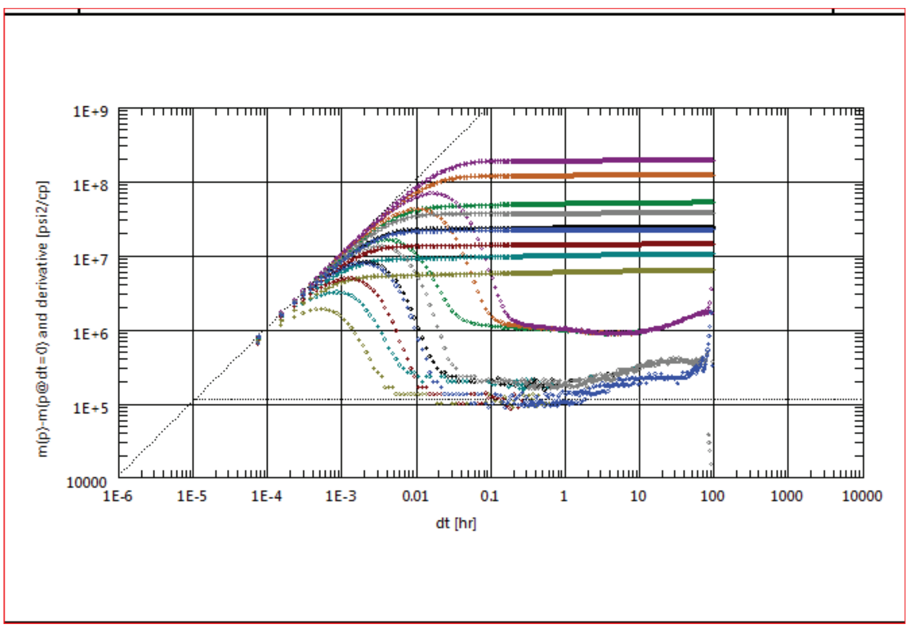


Figure 4: Log-Log plot for KOMA009 (D6000) Sensitivities

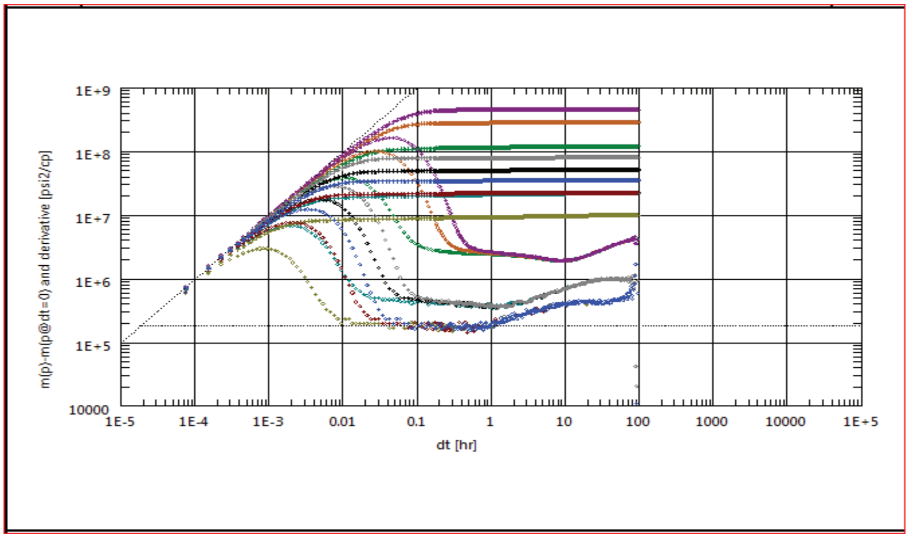


Figure 5: Log-Log plot for KOMA009 (D1000) Sensitivities

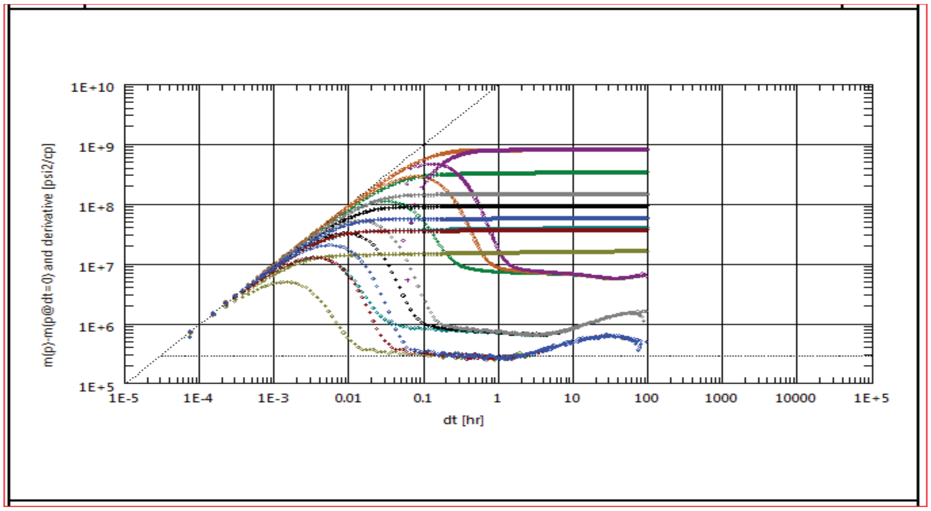


Figure 6: Log-Log plot for KOMA009 (C9400) Sensitivities

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 as detailed in the table below.

Table 9: Optimal Test Timing

Scenario	Initial Buildup (Pre Test) Hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
KOMA009: D6000	24	4	4	4	4	48	88
KOMA009: D1000	24	4	4	4	4	48	88
KOMA009: C9400	24	4	4	4	4	48	88

5.0 MRT WORKSCOPE SUMMARY

The summary of the MRT work scope for each interval is given as follows:

- After well clean-up, shut-in interval for 24 hours for initial reservoir stabilization
- Open up interval and conduct Multirate test (Tables 5 to 7)
- Shut in well for specified number of hours for final build-up test (Table 9).
- Secure well.
- RD equipment.

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.

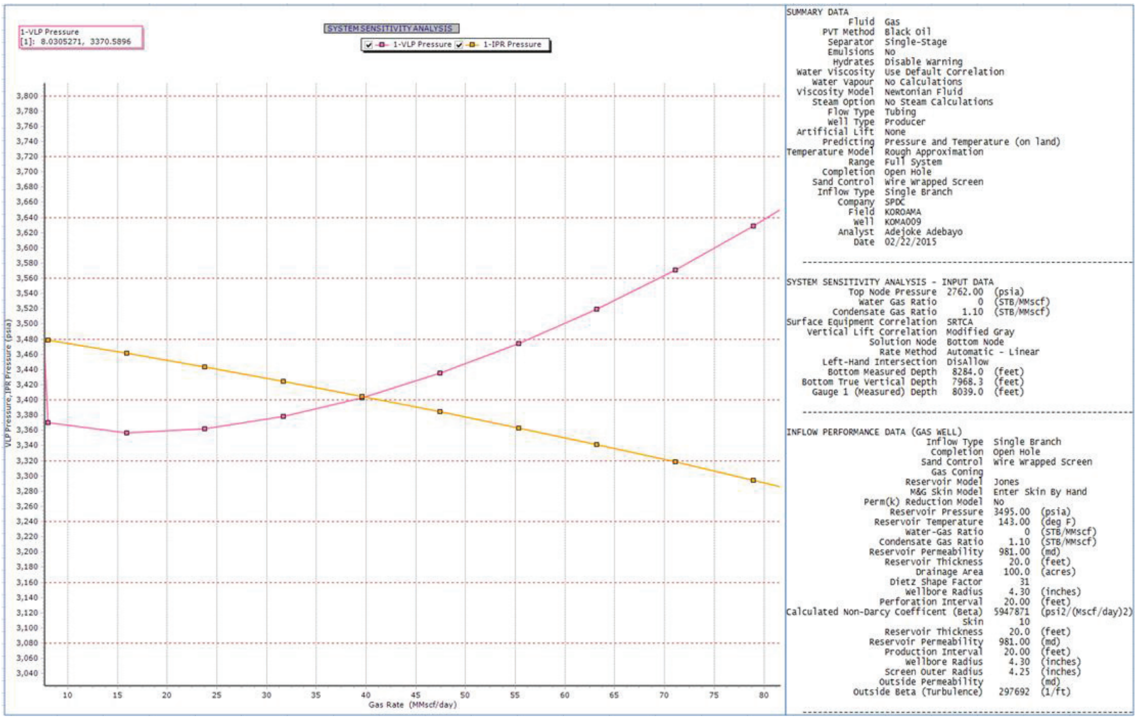
APPENDIX 1: RESERVOIR & COMPLETION DATA

KOROAMA – 009 Reservoir and Completions

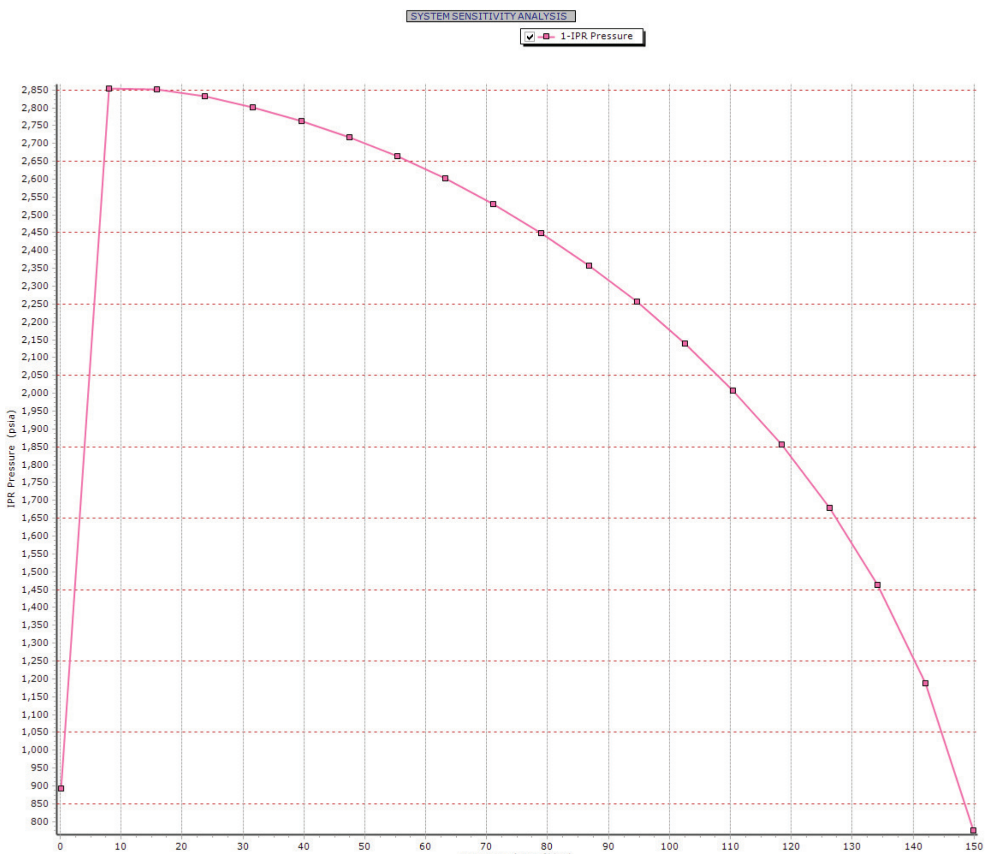
Target Reservoir	C9400X	D1000X	D6000X
1. Casing size and Type	9-$^5/_8$''/Production casing		
2. Casing Setting Depth (ftah)	8240		
3. Top of Sand [ftss/ftah]	7899/8284	8033/8431	8481/8962
4. Gross Sand Thickness (Gross) penetrated by Koroama-009(ft tv)	20	26	24
5. Well TD (ftss/ftah)	8520/ 9010		
6. a) Completion interval (ftss) b) Completion interval (fttvbdf) c) Completion interval (ftah)	7899 – 7919 7970 – 7990 8284 – 8307	8033 – 8059 8104 – 8130 8431 – 8460	8481 – 8505 8552 – 8576 8962 – 8991
7. Length of Completion Interval (ftah)	23	29	29
8. a) Top of competent cement (ftah) b) Source of data	5818 SBT		
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 35^0 across drain hole @ 8753 ftah		
10. Deviation at completion zone	29.2^0	28.24^0	31.77^0
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)	3495 7899 3495 143 7899 3495	3515 8033 3515 144 8033 3515	3719 8480 3719 149 8481 3724
12. Did RCI indicate abnormal pressures?	No		
13. Pressure gradient @ top of sand (psi/ft)	0.442	0.438	0.439
14. a) Is the reservoir fully gas-bearing?	Yes	Yes	Yes
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC(ft)	NO (GDT) 7975 N/A	YES 8071 N/A	YES 8564 N/A
16. Distance between lowest completion interval and GWC in well / reservoir (ftss)	>56	12	59
17. Is there a barrier between lowest completion interval and the present estimated GWC?	No	No	No
18. Gas S.G. (air=1)	0.61		
19. Condensate gravity (API)	44	44	44
20. Expected FTHP (psia)	2762	2766	2896
21. Expected CITHP (psia)	2850	2850	2990
22. Expected Drawdown (psi)	91	59	24
23. Is sand exclusion installed?	Yes OHESS	Yes OHESS	Yes OHESS

APPENDIX 2: WELL PERFORMANCE PLOTS

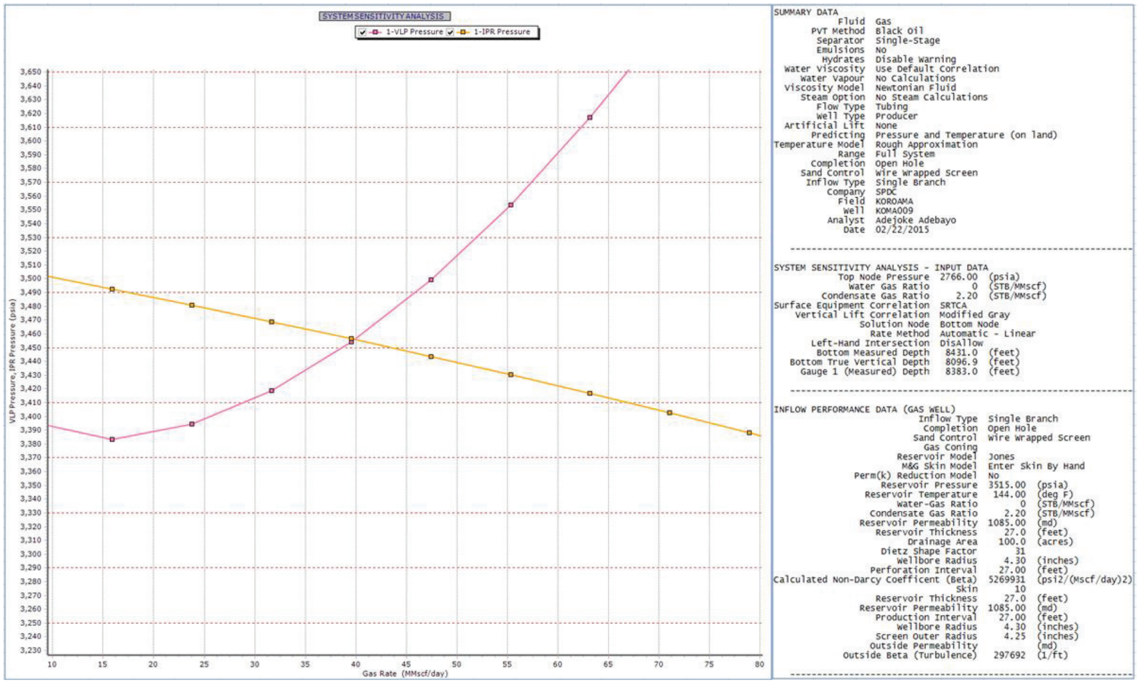
KOROAMA 009 C9400 MRT Well Performance



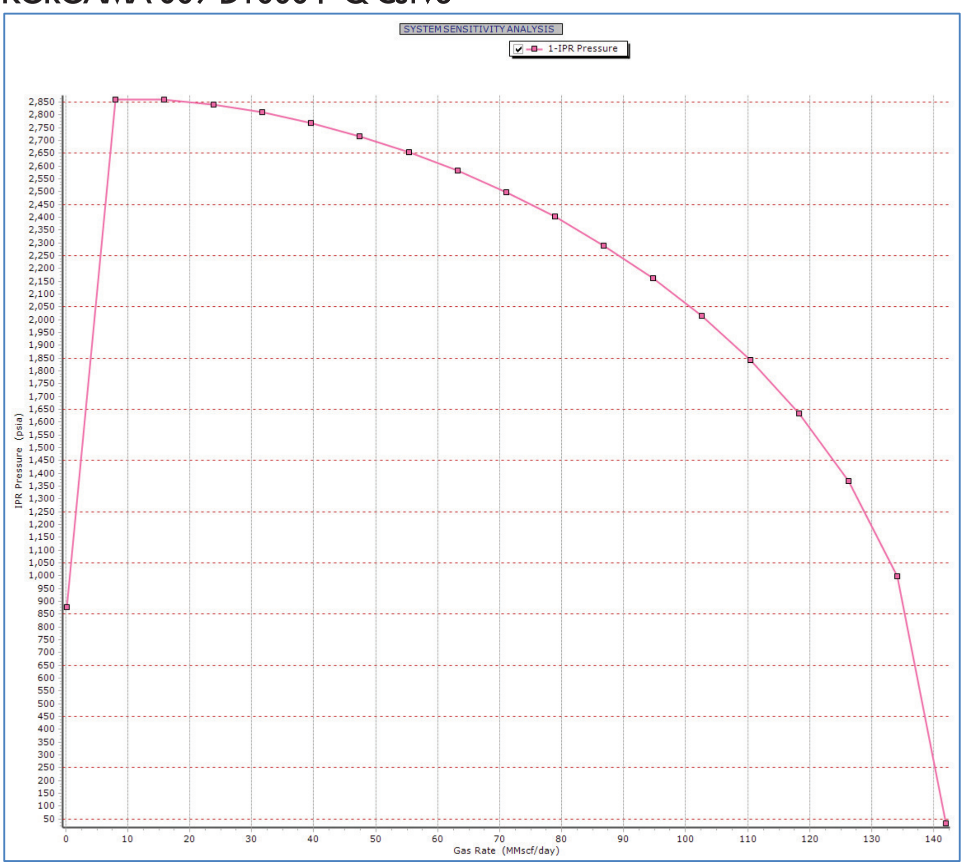
KOROAMA 009 C9400 P-Q Curve



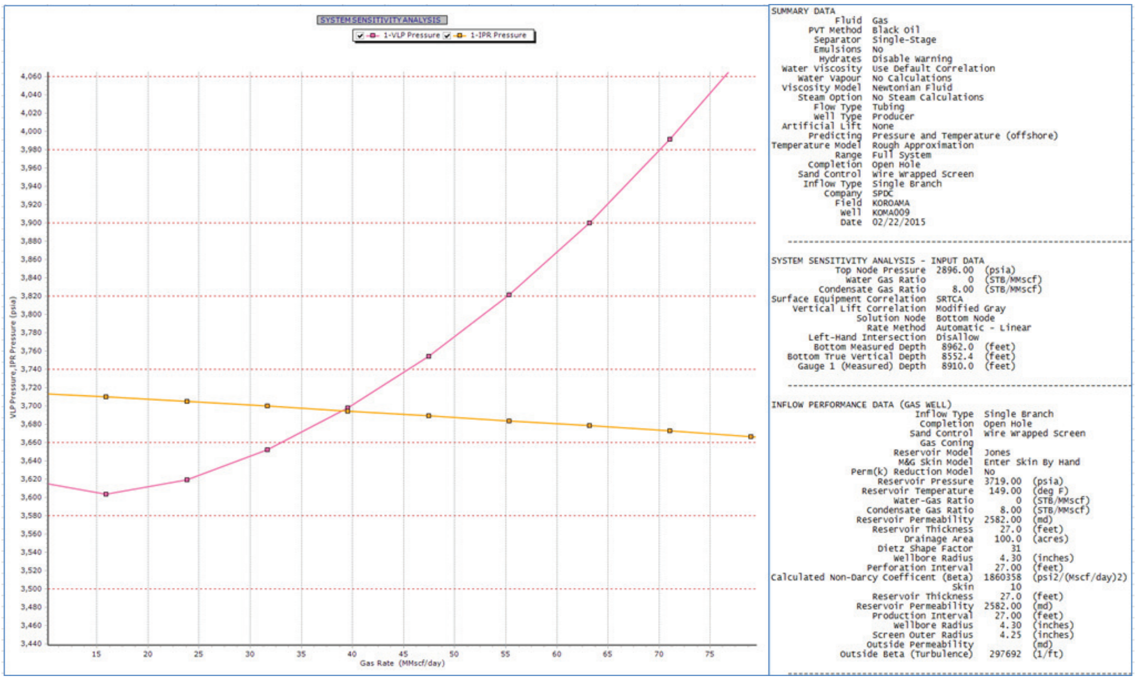
KOROAMA 009 D1000 MRT Well Performance



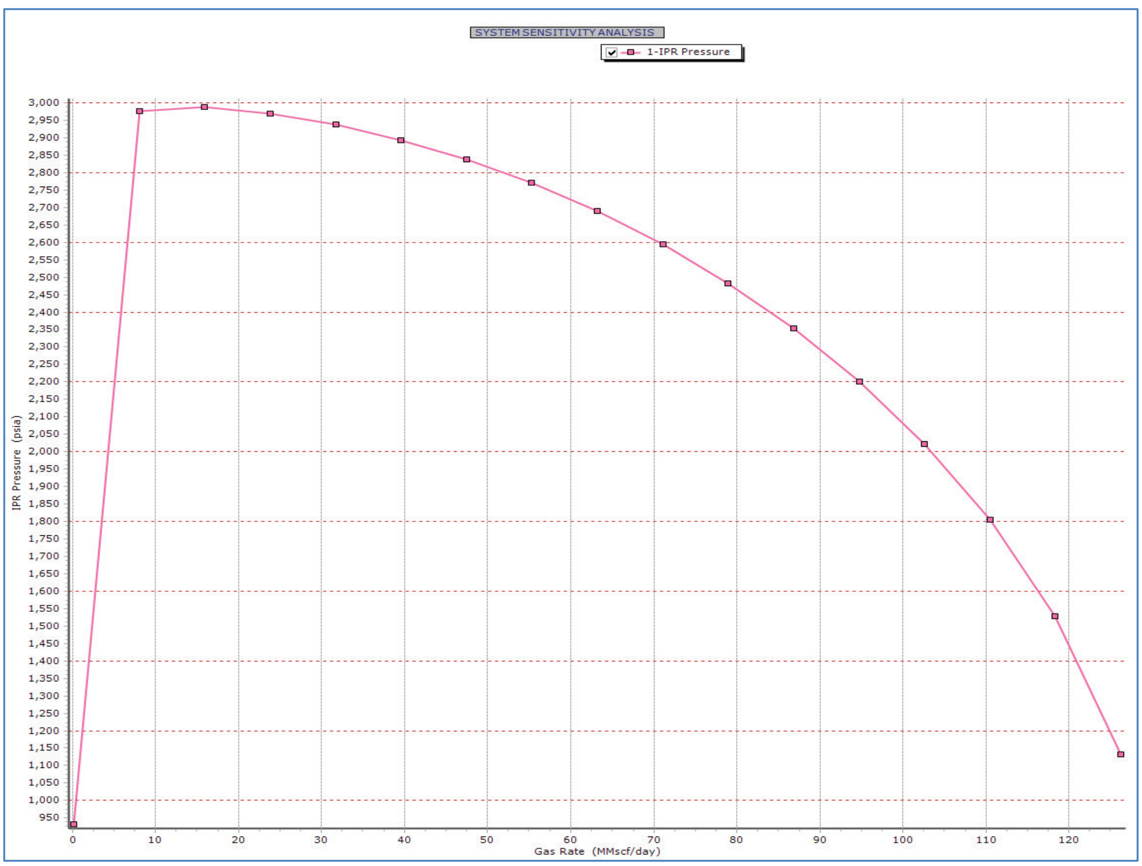
KOROAMA 009 D1000 P-Q Curve



KOROAMA 009 D6000 MRT Well Performance



KOROAMA 009 D6000 P-Q Curve



APPENDIX 3A: CRITICAL WELL TEST OPERATIONS RISKS/MITIGATION

Risk/Description	Consequence	Likelihood / Impact (L/M/H)	Mitigation
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	L/M	Ensure the dimensions of the tools to be RIH are appropriately sized for 3-1/2" tubing accessories/profiles ID
Emergency to spill, loss of containment	Loss of order, injury, fatality, loss of equipment	L/H	Ensure presence of 3-barriers at all time during clean-up/MRT operations. Also ensure all HAZID actions are closed-out prior to commencing operation
Hydrocarbon under pressure from kick or blowout	Explosion, loss of containment, injury, fatality and environmental pollution	L/H	Check integrity of the valves on the wellhead and WRSCSSV are integrity. Install surface readout gauges to monitor pressures and ensure BOP for the coil tubing unit is fully functional
Corrosive cleaning chemicals	Corrosion, environmental contamination.	L/H	Confirm that Nitrogen for lifting is tolerated by tubing/casing material.

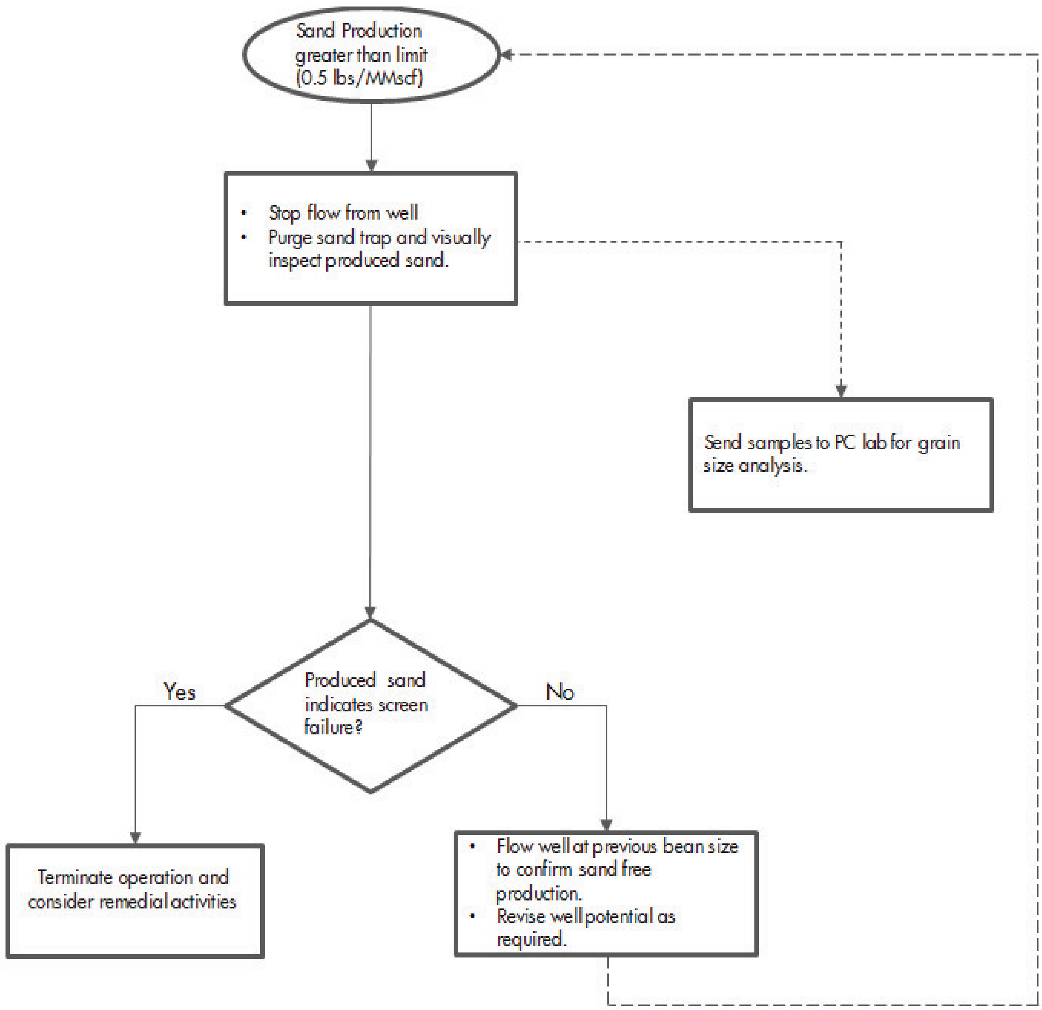
APPENDIX 3B: GAS WELL TEST RISKS/MITIGATION

Risk	Consequence	Mitigation
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Glycol will be injected at low gas rates to combat possible hydrate formation. At gas high rates, tubing temperatures are high enough to combat hydrate.
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.	13%Cr, completion material eliminates the need for corrosion inhibitor injection. Also wellhead have stainless steel clads.
Fire Source	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.
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 equipment.	Presence of 3-barrier containment Emergency Shut 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

APPENDIX 3C: DEP Table

DEP	Title	Remarks	Accountable DP
25.80.10.10-Gen	Formation Pore Pressure, Fracture Gradient (PP/FG) and Borehole Stability Prediction.	No drilling activity would be carried out during the operation	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 were done prior to drilling.	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 for KOMA009 is estimated at 731MMscf/d	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 done as an input to the Well proposal. Well has been completed with OHESS installed for sand control. Sand monitoring would be done during the well test.	PT

APPENDIX 3D: Sand production contingency plan



APPENDIX 4: Koroama-009 Final Completion Status Diagram

KOROAMA 9S1 FINAL COMPLETIONS SCHEMATIC

12th-June 2016

CASING

SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn	
24"	Stove Pipe		3500	Driven		Stovepipe
13-3/8"	K55	68	5,800	Class G	SLX	Surf Csg
9-5/8"	N80	47	8,240	Class G	SLX	Prod Csg

WELLHEAD (Surface Metal Seal 6 ported System)

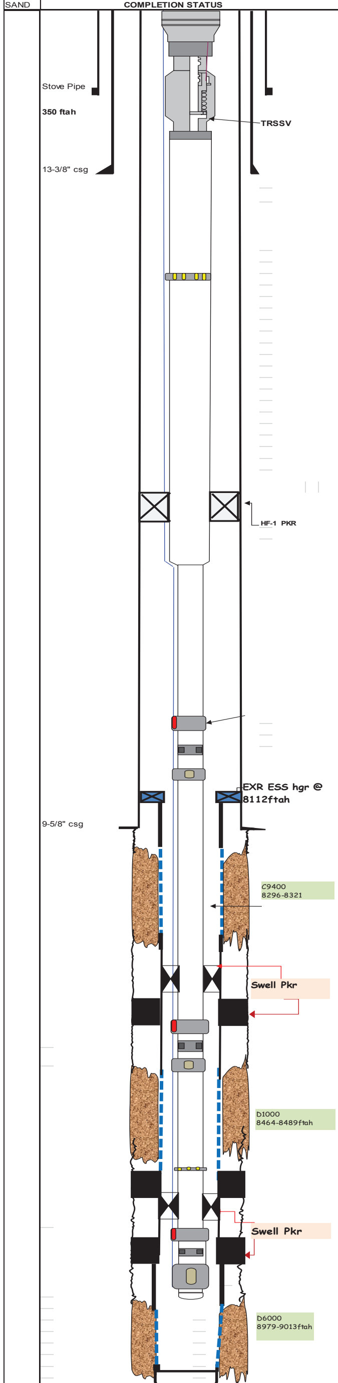
ITEM	TYPE	SIZE	WP
XMAS TREE	Compact	7-1/16" x 11" Flange block x 4-1/16" outlet	5,000 psi
TREE CAP	Cameron	7-1/16" c/w 4-1/16" Bore	5,000 psi
GATE VALVE	Cameron	7-1/16" c/w 4-1/16" Bore	5,000 psi
ACTUATOR VALVE	Cameron	7-1/16" c/w 4-1/16" Bore	5,000 psi
TUBING HANGER	Cameron	7-1/2" 6 Single Ported w/CL & PDHG Prep	5,000 psi
STARTER HEAD (CHH)	Cameron	13-3/8 x 13-5/8"	5000 psi
WELLHEAD HOUSING	Adapter spool	13-5/8" X 13-3/8"	5,000 psi
GATE VALVE	Cameron	2-1/16" c/w 2.060" Bore	5,000 psi

TUBING

STRING	SIZE	WT.	GRAD.	TYPE		
					MAX Deviation:	30.20°
					RT - Top XMT =	
	3-1/2"	9.2#	N80	HCS	DFE (RT - Compact Housing)= 34.66ft	
	5-1/2"	17#	N80	HCS	XMT =	

HOLE	DESCRIPTION	RESERVOIR
	CHESS/SMART Completions	C9.400, D1.000 & D6.000
Drill-in Fluid Type / Properties	POBM (10.0ppg) 0.52psi/ft	Max inclination 35.0deg @ 5,703ftah
Completion Fluid Type / Properties:	KCl Brine (0.48 psi/ft)	
Gas Pressure Gradient / Pressure:	0.705 sg/0.45psi/ft	

SAND / **COMPLETION STATUS**



Top Depth	Length	O.D.	I.D.	DESCRIPTION
- 0.00	34.66			Elevation
34.66	1.04	13.38	6.184	7" x 13-3/8" 5k psi prep for 6 ported Tubing Hanger
35.70	0.83	7.000	4.892	Crossover sub 7" 29# X5-1/2" 17# L-80 Hydri, 563 pin x pin
36.53	6.50	6.050	4.892	Pup Joint; 5-1/2" 17# L-80 Hydri,563 box x pin
43.03	111.21	6.050	4.892	4 Joints; 5-1/2" 17# Hydril,563 L-80 tubing
154.24	6.24	6.050	4.892	Pup Joint; 5-1/2" 17# L-80 Hydri, 563 box x pin
160.48	5.74	6.083	4.840	Flow Coupling, 5-1/2" 17" Hydril, 563 Box x Pin
166.22	**8.32**	**7.690**	**4.562**	**TRSV; SP 5-1/2" x 4.562" Seal Bore. 7.69" Max OD 13Cr H2S Service. 5-1/2" 17# TSH563**
174.54	5.74	6.083	4.840	Flow Coupling, 5-1/2"17" Hydril 563 Box x Pin
180.28	3.93	6.050	4.892	Pup Joint; 5-1/2" 17# L-80 Hydri, 563 box x pin
184.21	7,820.50	6.050	4.892	**212 Joints; 5-1/2" 17# Hydril,563 L-80 tubing**
8,004.71	6.22	6.050	4.892	Pup Joint;5 1/2" 17# TSH 563 Pin x x 5-1/2 17#Vam Top Pin
8,010.93	**14.65**	**8.431**	**4.562**	**HF-1 Packer 5.5" 17# Vamtop Box X Pin,with 5 1/2" Splice Sub**
8,025.58	1.22	6.050	2.992	Crossover, 5 1/2" 17# Hydril 563 Box x 3-1/2" 9.2# Hydril 563 Pin
8,026.80	2.37	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,029.17	2.36	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,031.53	6.46	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,037.99	1.21	4.250	2.992	Adapter Sub; 3-1/2 9.2# TSH 563 Box x3-1/2" 9.2# Hydril CS Pin
8,039.20	**6.62**	**5.226**	**2.949**	**Permanent Monitoring Gauge Integrations, 3 1/2 TUBING DIAMETER, 9.20 lb/ft TUBING WEIGHT HCS BXP**
8,045.82	1.09	4.250	2.992	Adapter Sub; 3-1/2 9.2# Hydril CS Box x 3-1/2" 9.2# TSH 563 Pin
8,046.91	1.38	3.970	2.750	**2.750 RPT Landing Nipple 3.5" 9.2# H563 BX P**
8,048.29	2.24	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,050.53	2.00	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,052.53	1.17	4.250	2.992	Adapter Sub; 3-1/2" 9.2# TSH 563 Box x 3-1/2 9.2# Vam Top Pin
8,053.70	5.08	4.250	2.992	4ft Pup Joint 3-1/2" 9.2# Vam top Box x Pin
8,058.78	**5.81**	**5.865**	**2.750**	**VALVE, HS, 3-1/2,10.20 VAMTOP BOX, 3 1/2-10.20 VAMTOP PIN,**
8,064.59	1.12	4.250	2.992	Adapter Sub; 3-1/2" 12.6# Vam Top Box Box x 3-1/2 9.2# TSH 563 Pin
8,065.71	4.25	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,069.96	248.82	4.250	2.992	**TUBING 3.5" 3-1/2" 9.2# L-80 Hydri, 563 box x pin**
8,318.78	6.11	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,324.89	1.35	5.966	2.992	Adapter Sub;3-1/2 9.2# TSH 563 Box 4-1/2"12.75# Vam Top Pin
8,326.24	6.15	4.966	2.992	4/2"Swell Packer base pipe stickout with 4-1/2 vamtop box
8,332.39	**29.64**	**6.380**	**3.958**	**Halliburton FT Swell Packer 7 5/8 in., 24-29.7 lb/ft Weight Range Vam Top**
8,362.03	3.58	4.500	2.992	4/2"Swell Packer base pipe stickout with 4-1/2 vamtop pin
8,365.61	1.27	4.250	2.992	Adapter Sub; 4-1/2 12.75# Vam Top Box x 3-1/2" 9.2# TSH 563 Pin
8,366.88	6.19	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,373.07	4.17	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,377.24	4.29	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,381.53	1.19	4.250	2.992	Adapter Sub; 3-1/2 9.2# TSH 563 Box x3-1/2" 9.2# Hydril CS Pin
8,382.72	**6.62**	**5.226**	**2.949**	**Permanent Monitoring Gauge Integrations, 3 1/2 TUBING DIAMETER, 9.20 lb/ft TUBING WEIGHT**
8,389.34	1.13	4.250	2.992	Adapter Sub; 3-1/2 9.2# Hydril CS Box x 3-1/2" 9.2# TSH 563 Pin
8,390.47	2.11	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,392.58	2.20	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,394.78	1.17	4.250	2.992	Adapter Sub; 3-1/2" 9.2# TSH 563 Box x 3-1/2 9.2# Vam Top Pin
8,395.95	5.11	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Vamtop, 563 box x pin
8,401.06	**5.79**	**5.865**	**2.748**	**VALVE, HS, 3-1/2,10.20 VAMTOP BOX, 3 1/2-10.20 VAMTOP PIN,**
8,406.85	1.12	4.250	2.992	Adapter Sub; 3-1/2" 12.6# Vam Top Box Box x 3-1/2 9.2# TSH 563 Pin
8,407.97	4.26	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,412.23	373.15	4.250	2.992	**12 Joints; 3-1/2" 9.2# Hydril,563 L-80 tubing**
8,785.38	6.13	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,791.51	1.35	3.915	2.992	Adapter Sub; 3-1/2" 9.2# TSH 563 Box 4-1/2 12.75# Vam Top Pin
8,792.86	6.17	4.966	**3.958**	**4/2"Swell Packer base pipe stickout with 4-1/2 vamtop box**
8,799.03	**29.75**	**6.380**	**3.958**	**Halliburton FT Swell Packer 7 5/8 in., 24-29.7 lb/ft Weight Range Vam Top**
8,828.78	**3.53**	**4.500**	**3.958**	**4/2"Swell Packer base pipe stickout with 4-1/2 vamtop pin**
8,832.31	1.27	4.966	2.992	Adapter Sub; 4-1/2 9.2# Vam Top Box x 3-1/2" 9.2# TSH 563 Pin
8,833.58	6.21	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,839.79	62.71	4.250	2.992	**2 Tubing Joints; 3-1/2" 9.2# Hydril,563 L-80 tubing**
8,902.50	6.31	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,908.81	1.08	4.250	2.992	Adapter Sub; 3-1/2 9.2# TSH 563 Box x3-1/2" 9.2# Hydril CS Pin
8,909.89	**6.61**	**5.235**	**2.916**	**Permanent Monitoring Gauge Integrations, 3 1/2 TUBING DIAMETER, 9.20 lb/ft TUBING WEIGHT**
8,916.50	1.01	4.260	2.750	**Otis X Selsective Landing Nipple 2.75"**
8,917.51	1.11	3.915	2.992	Adapter Sub; 3-1/2 9.2# Hydril CS Box x 3-1/2" 9.2# TSH 563 Pin
8,918.62	2.30	3.915	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,920.92	2.18	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,923.10	1.71	3.909	2.944	Adapter Sub; 3-1/2" 9.2# TSH 563 Box x 3-1/2 9.2# Vam Top Pin
8,924.81	4.96	4.250	2.965	Pup Joint 3-1/2" 9.2# Vam top Box x Pin
8,929.77	**5.77**	**5.865**	**2.748**	**ICV VALVE, HS, 3-1/2,10.20 VAMTOP BOX, 3 1/2-10.20 VAMTOP PIN,**
8,935.54	1.03	4.250	2.992	Adapter Sub; 3-1/2" 12.6# Vam Top Box Box x 3-1/2 9.2# TSH 563 Pin
8,936.57	6.34	4.250	2.992	**Pup Joints; 3-1/2" 9.2# Hydril,H563 L-80 tubing**
8,942.91	6.32	4.250	2.992	Pup Joint; 3-1/2" 9.2# L-80 Hydri, 563 box x pin
8,949.23	0.72	4.250	-	**Bull Plug, 3-1/2" 9.2# L-80 13Cr Box**
8,949.95				**End Of Completion Assy**

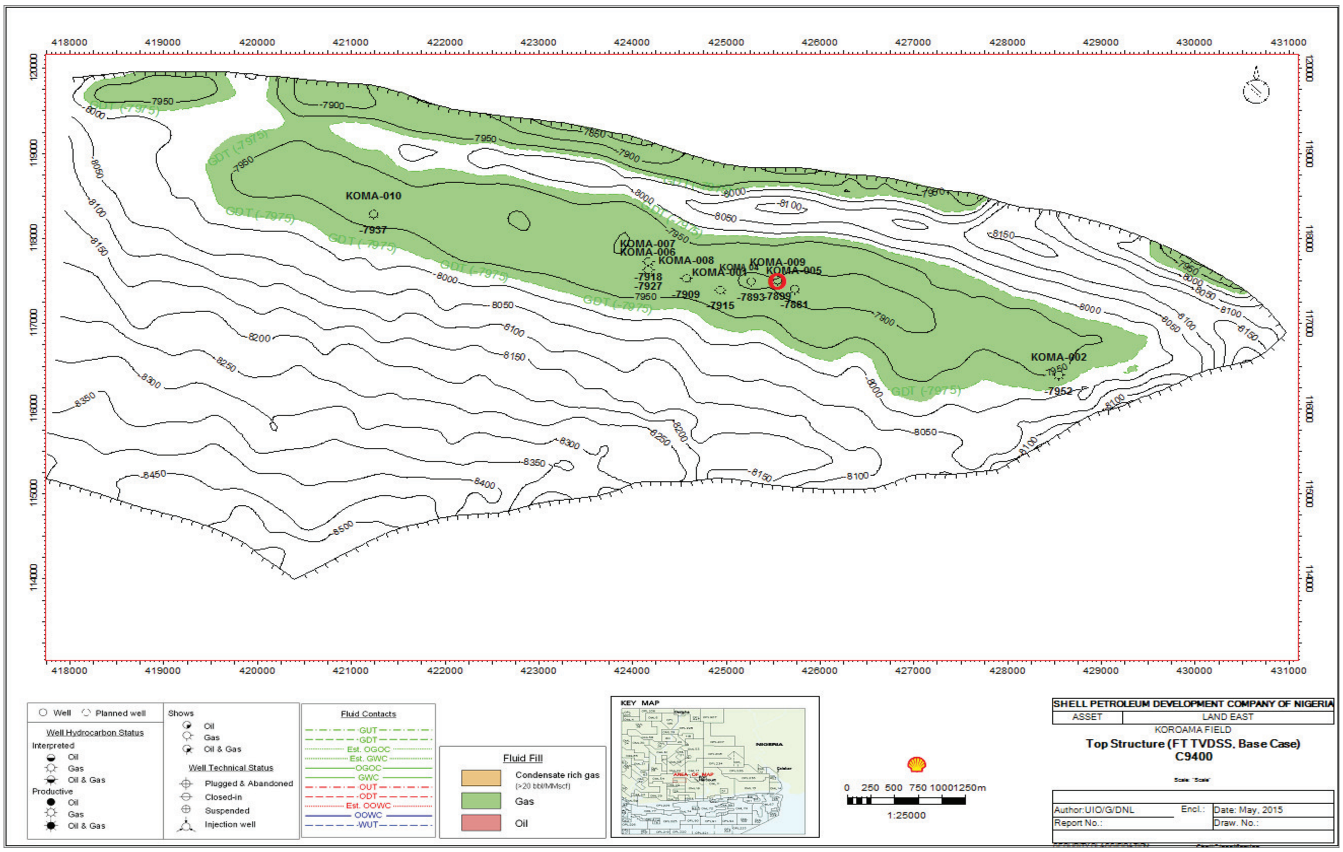
LOWER COMPLETIONS ESS ASSY

Top Depth	Length	O.D.	I.D.	DESCRIPTION
8,112.29	11.37	8.400	6.800	**Cardium EXR 7-5/8" x 9-5/8 " Hanger**
8,123.66	10.23	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Pup Joint
8,133.89	132.67	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing
8,266.56	5.73	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Pup Joint
8,272.29	2.90	8.681	6.875	5-1/2" Mark II ESS ETC, 270 micron with 7 5/8" 29.7# FJL box x MKII pin
8,275.19	37.68	8.500	7.200	5-1/2" E.S.S Mark II, ESS 270 micron with ESS MKII box x pin
8,312.87	3.23	8.500	7.200	5-1/2" Mark II ESS EBC, 270 micron with ESS MKII box x 7 5/8" 29.7# FJL pin
8,316.10	19.99	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Pup Joint
8,336.09	**22.56**	**8.250**	**6.875**	**7 5/8" 29.7# Hybrid Swell Packer with 7 5/8" 29.7# FJL box x pin**
8,358.65	56.73	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing (RIH pup jt followed by 1 full jt)
8,415.38	5.75	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Pup Joint
8,421.13	2.90	8.681	6.875	5-1/2" Mark II ESS ETC, 270 micron with 7 5/8" 29.7# FJL box x MKII pin
8,424.03	**37.68**	**8.500**	7.200	5-1/2" E.S.S Mark II, ESS 270 micron with ESS MKII box x pin
8,461.71	3.24	8.500	7.200	5-1/2" Mark II ESS EBC, 270 micron with ESS MKII box x 7 5/8" 29.7# FJL pin
8,464.95	6.24	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing
8,471.19	**22.56**	**8.250**	**6.875**	**7 5/8" 29.7# Hybrid Swell Packer with 7 5/8" 29.7# FJL box x pin**
8,493.75	396.04	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing
8,889.79	**22.56**	**8.250**	**6.875**	**7 5/8" 29.7# Hybrid Swell Packer with 7 5/8" 29.7# FJL box x pin**
8,912.35	44.00	7.625	6.875	7-5/8" 29.7# Vam FJL box x pin Spacer Tubing
8,956.35	2.90	8.500	6.875	5-1/2" Mark II ESS ETC, 270 micron with 7 5/8" 29.7# FJL box x MKII pin
8,959.25	**37.68**	**8.500**	**7.200**	5-1/2" E.S.S Mark II, ESS 270 micron with ESS MKII box x pin
8,996.93	9.77	8.500	4.803	5-1/2" Mark II ESS EBC, 270 micron with ESS MKII box x 7 5/8" 29.7# FJL pin
9,006.70	1.30	6.060		Bull plug, 5-5/8" SA 8TPI Box up.
9,008.00				

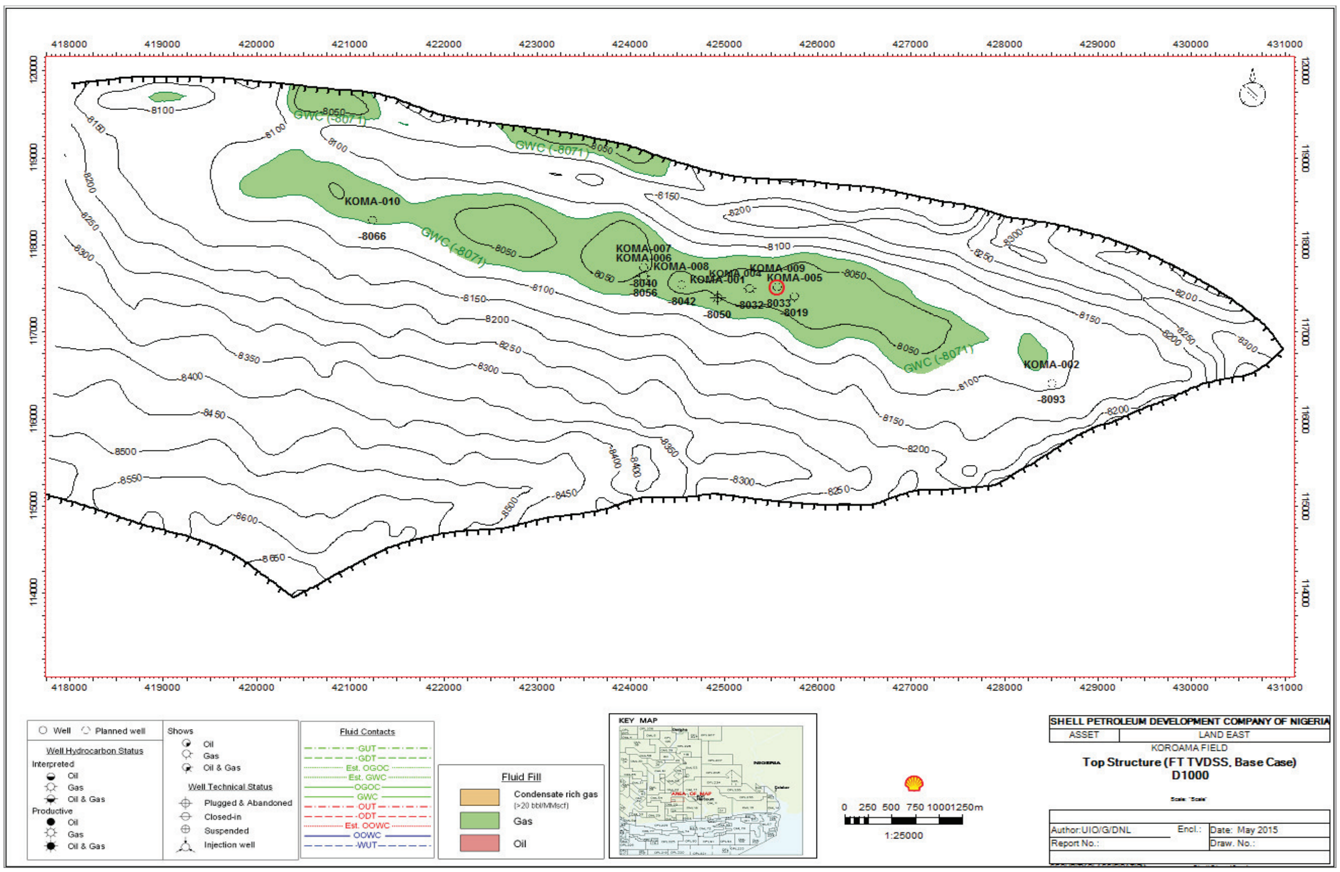
TD	**9050ftah**	Completed b Godwin Lawson/Justus N.	DATE COMPLETED: 12th June 2016	Checked by:	Approved by:

APPENDIX 5: Top Depth Map of the KOMA009 C9400X, D1000X and D6000X sands

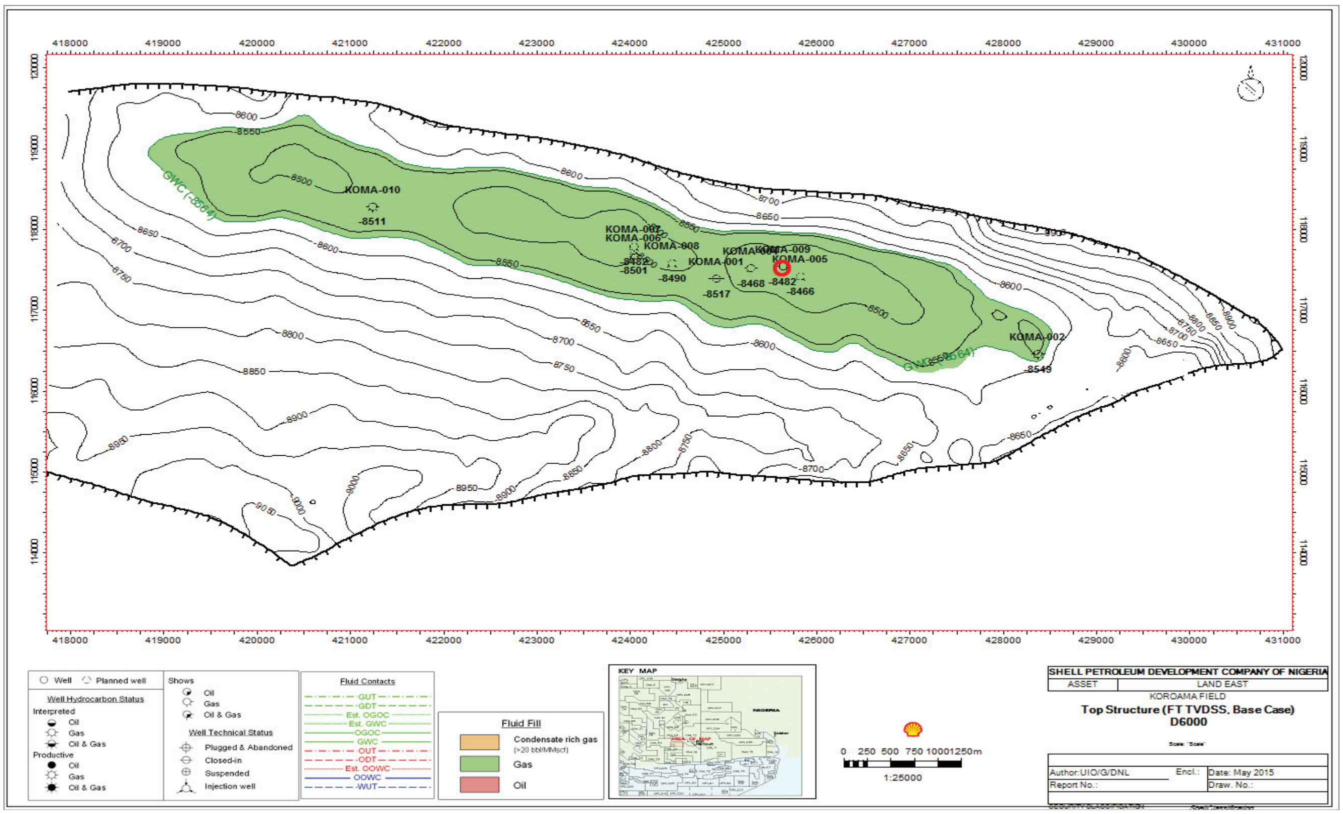
Top Depth Map of the KOMA009 C9400X sand



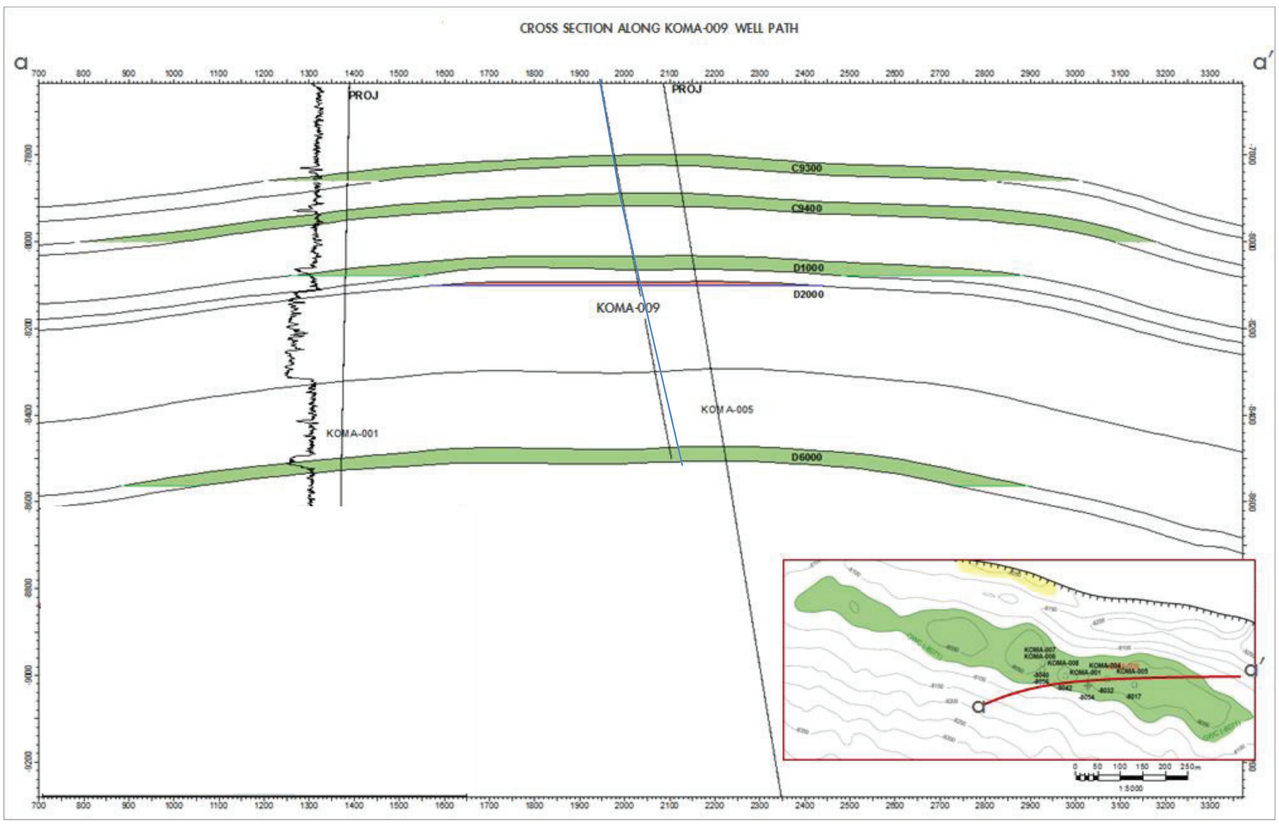
Top Depth Map of the KOMA009 D1000X sand



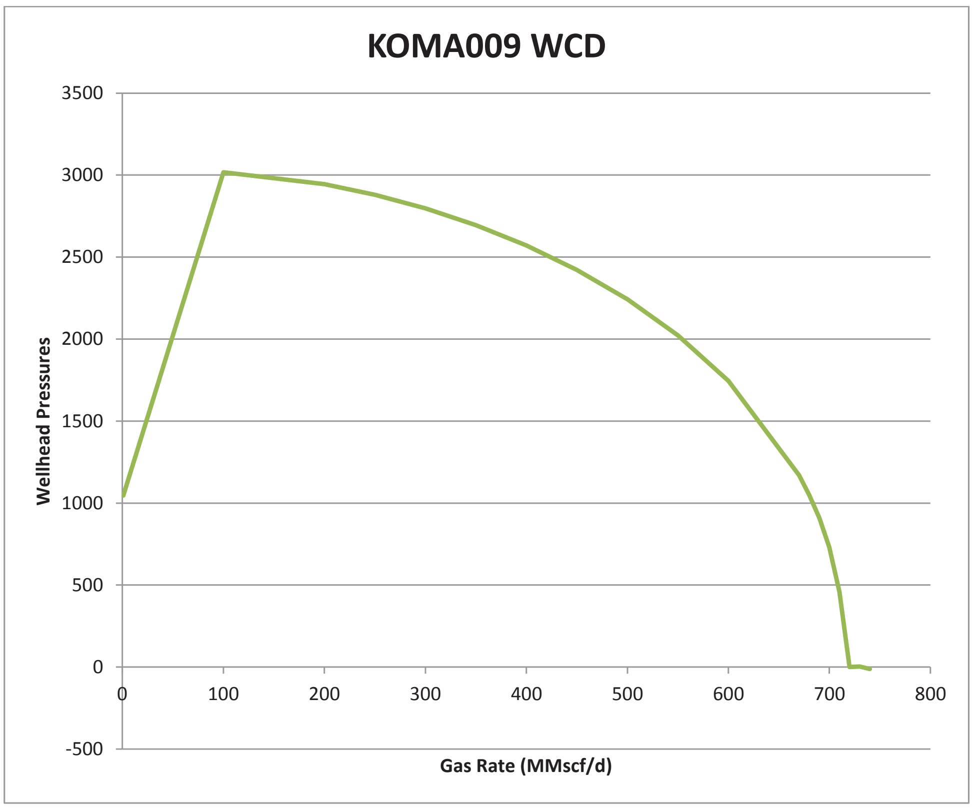
Top Depth Map of the KOMA009 D6000X sand



APPENDIX 6: Cross section along KOMA009 well path



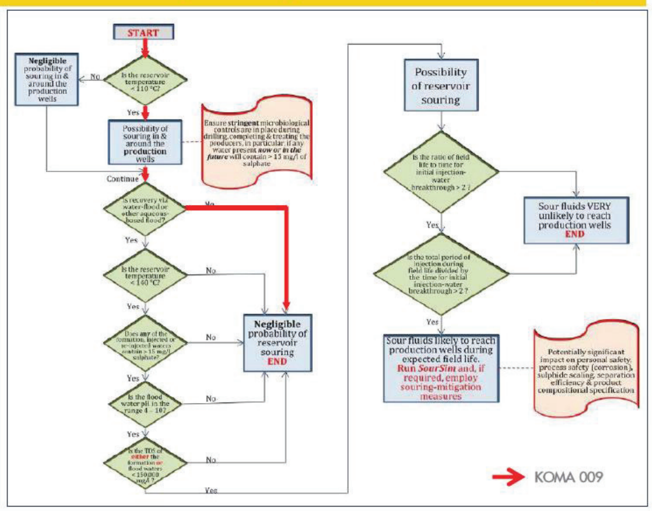
APPENDIX 7: Worst Case Discharge plot for KOMA009



APPENDIX 8: KOMA009 H_2S Prediction

KOMA 009 H_2S PREDICTION (C9400, D1000 AND D6000)

- KOMA009 is planned to be completed on C9400, D1000 and D6000.
- PVT data available for C9400, D6000, E7000 and F1000 reservoirs indicate no presence of H_2S.
- There is no PVT data available for D1000, however the D7000, E1000 and F1000 reservoirs are currently producing with no H_2S production recorded.
- Production Operations and Production Chemist have not encountered H_2S in the Gbaran nodal area.
- Expected Reservoir Temperature in C9400, D1000 and D6000 are 62ºC, 63ºC and 66ºC respectively.
- No water-flood is planned for the field
- Hence, the souring potential is negligible.
- Gas testers and appropriate PPE's will be utilized during completion and well open up as additional mitigation.



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SPDC

Date: 5/5/2016 2

THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOROAMA-011 WELL CLEAN-UP/TEST PROPOSAL

September 2016

Well No	KOROAMA-011
Reservoir	D8200X

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1.0 BACKGROUND

Koroama-011 is a gas development well that was drilled to provide a drainage point on the D8200X reservoir and develop 169 Bscf of gas and 1.5 MMstb at an initial production potential of 60 MMscf/d. The well was spudded on the 17th April 2016, drilled to a TD of 10,603 ftah (9,250 ftss), and completion operation ended on 27th May 2016. The well partially penetrated the D8200X sand at 9,197 ftss, 33 ft deeper than prognosis and encountering a gross gas column of 41 ft tvd.

Reservoir	2P Gas UR (Bscf)	2P Condensate UR (MMbbl)	Gas Rate (MMscf/day)
D8200X	169	1.5	60

The well was drilled and completed as a Single String Single (SSS) gas producer on the D8200X gas reservoir with 7" 13Cr tubing equipped with Tubing Retrievable Surface-Controlled Subsurface Safety Valve (TRSCSSSV). The PDHG initially planned for the well could not be installed due to operational constraints. External gravel pack (EGP) was installed across the sand face for effective sand control.

KOMA-011 is the only well completed on the Koroama D8200 reservoir, hence no production has been recorded from the reservoir.

It is proposed to clean up the well to about 50 MMscf/d to remove drilling and completion debris and fluids and conduct Multirate test to ca. 50 MMscf/d on the D8200 interval. This is due to the limit of the contractor's facilities. Results from the MRT will be used to calibrate the well deliverability.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to remove 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 Gbaran CPF as part of the wells delivering gas to the NLNG T1 – T6. 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 D8200X interval
- Carry out MRT on D8200X interval and carry out SG survey

2.0 WELL CLEAN-UP DESIGN

During the clean-up operation, KCl brine will be pumped to displace Thixsal mud. Then, 10% HCL will be jetted across the gravel pack screen in a minimum of 3 passes. The well should be flowed long enough 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), flow will be stopped pending review of operation. See 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.

2.1 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
- Downhole Shut in tool
- Clamp on sand monitor
- 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 (Compulsory requirement)
- Mono- Ethyl Glycol (To mitigate hydrates at low rates)

2.2 Well Clean-Up Operation

The well cleanup operation will commence with unloading operation via coiled tubing. The clean-up will then commence from choke 34/64th (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 WGR ca. 0 bbl/MMscf is achieved. Thereafter, the well will be shut-in for 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

The flow back well effluent (completion brine) 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:

- RIH CT with impact hammer to break the flapper at 10,393 ftah (Confirm flapper is completely broken and no any other restriction through the EGP)
- RIH CT while pumping KCl brine to displace Thixsal mud.
- Clean up by making minimum of three passes, jetting 10% HCl across the screen
- Circulate hole with KCl brine to displace spent acid and POOH CT
- Pump nitrogen (if required) to lift until well is confirmed to sustain natural flow
- Clean-up well as per program (Table-1)
- Shut-in well for 24 hours for initial reservoir stabilization

NOTE:

- Initial opening of well must be during daylight.
- Neutralize acid in flow back tank using soda ash (K-35) before dumping at the flow station.
- Bean-up must be done gradually to achieve good bridging behind EGP.
- 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, not exceeding a maximum gas rate of 50 MMscf/d. Well is properly cleaned-up when at least 80% of expected FTHP is achieved on any bean shown in Table-1 below.
- All temporary pipe connections must be properly secured and tested to expected pressures

Table 1: KOROAMA-011 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	34	0	2991	4*	67	Take sample, check for sand, measure FTHP.
30	40	0	3032	2**	96	Take sample, check for sand, measure FTHP.
40	48	0	2987	2**	143	Take sample, check for sand, measure FTHP.
50	54	0	2941	**4****	186	Take sample, check for sand, measure FTHP.

*Recommended flow period however well to flown on this bean until clean-up criteria is achieved.
****** Stabilized flow after achieving clean up criteria on each bean

Clean up criteria
Stabilized THP for 1 hour
BSW of liquid sample </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 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 R nipple (10,166 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.
- RD equipment.

3.1 Initial Build-up Period

- Close in well at choke manifold for 24 hours for an initial build-up 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 "R – Nipple" (ca.10,166 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) (1/64th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period* (hr)	Expected Drawdown (psi)	Comments
20	34	0	2991	4	67	Take sample, check for sand, measure FTHP.
30	40	0	3032	4	96	Take sample, check for sand, measure FTHP.
40	48	0	2987	4	143	Take sample, check for sand, measure FTHP.
50	54	0	2941	4	186	Take sample, check for sand, measure FTHP.
0	0	0	-	48	0	48hr shut in period

**Bean up should be carried out when flow stabilizes and FTHP & BSW are stable for at least 1 hour.*

- 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).

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 and compare to real time fiber optic data.
- Close TRSCSSSV and line up well to production.
- Handover well to production.

Table 3: Static Gradient Survey Stops.

Depth Tag (d)	Depth (d)	di-1-di	Time at depth	Comment/Basis for Stops Selection
	ftah from DFE [DFE Elevation = 35 ft]	Ft	Minutes	
Deepest Survey Depth	10166	-	0	Deepest Survey depth. R nipple Depth
1st Stop	10146	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	10126	20	10	
3rd Stop	10106	20	10	
4th Stop	9906	200	10	2nd Set of Stops: 4 Stops at 200ft intervals to ensure accurate estimate of well fluid gradient
5th Stop	9706	200	10	
6th Stop	9506	200	10	

Depth Tag (d)	Depth (d)	di-1-di	Time at depth	Comment/Basis for Stops Selection
	ftah from DFE	Ft	Minutes	
7th Stop	9306	200	10	3rd Set of Stops: 2 Stops at 500ft intervals to ensure accurate estimate of well fluid gradient
8th Stop	8806	500	10	
9th Stop	8306	500	10	
10th Stop	7306	1000	10	4th Set of Stops: 2 Stops at 1000ft intervals to ensure accurate estimate of well fluid gradient
11th Stop	6306	1000	10	
12th Stop	4306	2000	10	
13th Stop	2306	2000	10	5th Set of Stops: 3 Stops at 2000ft intervals to ensure accurate estimate of well fluid gradient
14th Stop	306	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 1. Pressure simulations were generated based on the rates in section "e" of Table 34. 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 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
a. Reservoir Data			
Pay Zone Thickness	45	ft	
Average Formation Porosity	0.24	fraction	
Formation Compressibility	3.32E-06	psi-1	Estimated using Hall correlation.
Reservoir Pressure	4420	psi	Estimated current pressure based on BHP Data (No production history from reservoir)
Reservoir Temperature	159	deg^{O}F	
Reservoir Permeability	2179	md	Mean reservoir permeability calculated from FZI analysis using logs acquired from
b. Well Data			
Well Orientation	Vertical		
Well Radius	0.35	ft	

Parameter	Value	Unit	Comment
Well bore Storage (WBS) Coefficient	0.0768	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	0.61		
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model			
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 104mD, 2179mD and 5400mD respectively were derived and used in the design.

BOUNDARY MODEL:

The TOP structure Map (Appendix 5) was digitized and used in the design. The reservoir is bounded by a GWC at 9335 ftss. From the top structure map and cross section (Appendix 5&6), the reservoir geometry is relatively simple. A review of the structure shows that the reservoir is fault bounded at the north by the boundary fault and closed at the east and south but open at the western flank. This formed the basis for digitizing the map with 3 closed boundaries and the western boundary open to flow with a leakage factor of 1. With no intra reservoir faults, the outer boundary to be seen by the well will likely be the boundary faults.

SKIN:

No data was available to evaluate the possible skin values that may exist in reality. However, skin values of 17.7, 52.85 and 88 (selected based on expected skin range for External Gravel pack completion) was studied.

WELLBORE STORAGE:

A wellbore storage coefficient of 0.0768 bbl/psi was estimated for surface shut in. The well test design was carried out using well bore storage of 0.0768 bbl/psi 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.

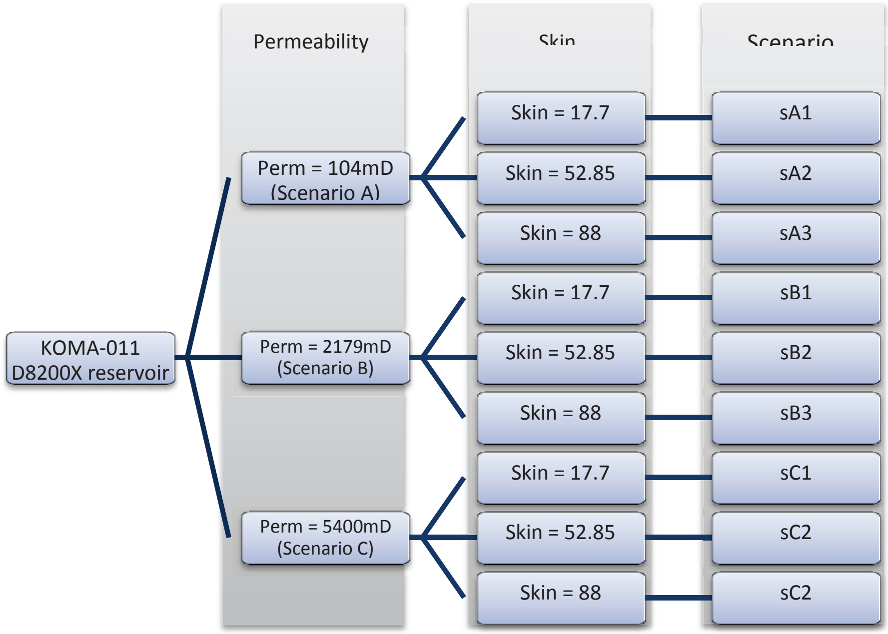


Figure 1: Scenario

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 minute details often approximated in the analytical method.

Simulated pressure responses were generated for the test design using 4-hourly three stepped rates (20, 40, & 60 MMscf/d respectively).

Based on available data from wells which were completed on the interval, the D8200X shows a permeability range of 104mD to 5400mD. These values were based on log data from KOMA 002, 010 and 001. The initial reservoir pressure value of 4022 psia was used in the evaluation based on the fact that wells are yet to produce from this reservoir.

The derivative plots for the different scenarios can be seen in figures 2, 3 and 4. From the figures, the following can be deduced

1. The variation in the skin values will not result in any significant distortion to the expected reservoir behaviour and no impact on the time to the outer boundary from the test.
2. The late time pressure response indicated an outer boundary primarily dominated by a parallel fault boundary effect in the cases of permeability of 104mD and 2179mD. In the 5400mD permeability scenario, a slight deviation was observed around 50 hours of shut-in. this is most likely to be caused by the effects of the closed boundary to the east and the open boundary to the west. However, more time is required to be able to define properly the outer boundary effect seen by that response.
3. With the assumed base-case permeability of 2179 mD, a minimum of 8 hours is required for the final build up test. For the permeability value of 104mD, a minimum of 48 hours is required for the outer boundary effects to be felt by the test and pressure stabilization achieved. The outer boundary effects will be felt as early as 5 to 10 hours.

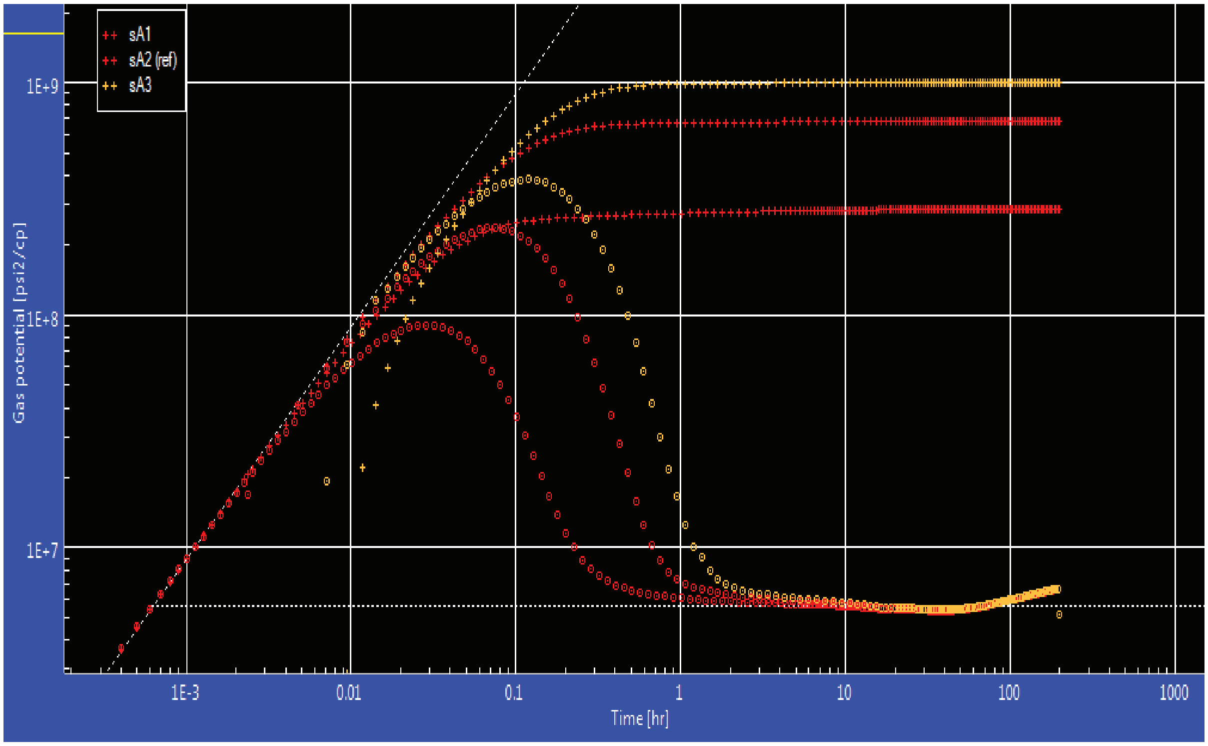


Figure 2: Log-Log plot for Scenario A: sA1 (Perm/Skin: 104mD/17.7), sA2 (Perm/Skin: 104mD/52.85), sA3 (Perm/Skin: 104mD/88)

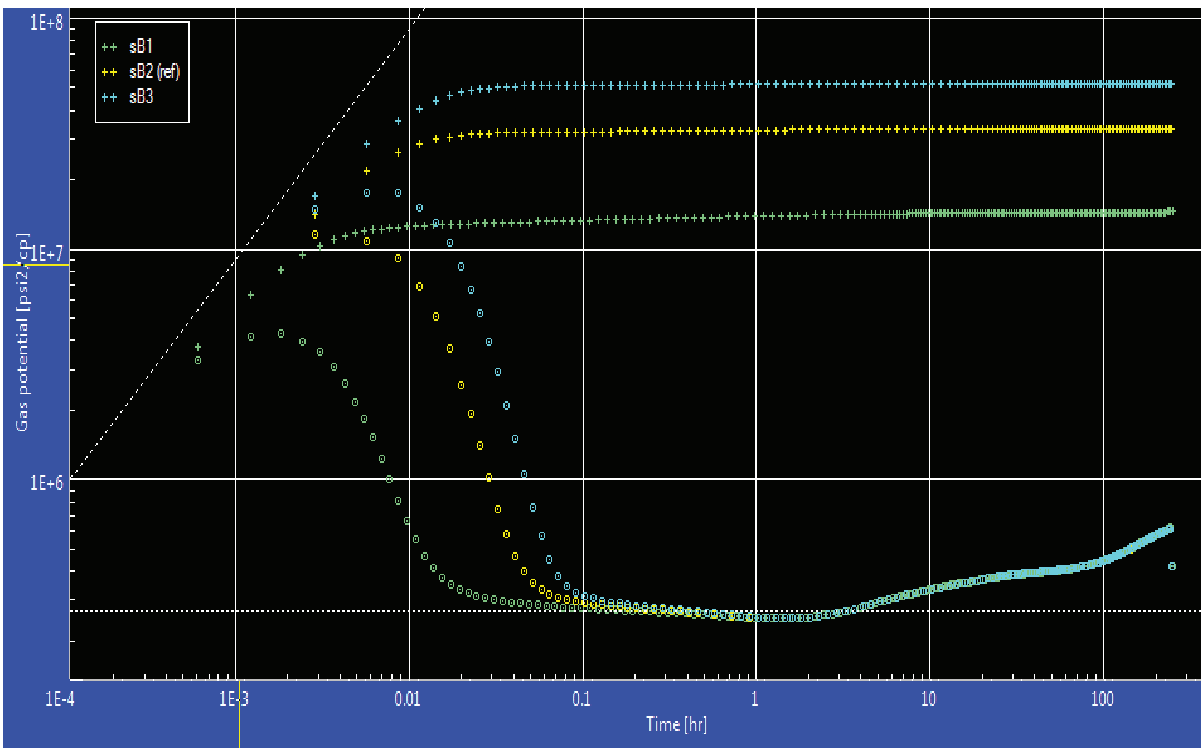


Figure 3: Log-Log plot for Scenario B: sB1 (Perm/Skin: 2179mD/17.7), sB2 (Perm/Skin: 2179mD/52.85), sB3 (Perm/Skin: 2179mD/88)

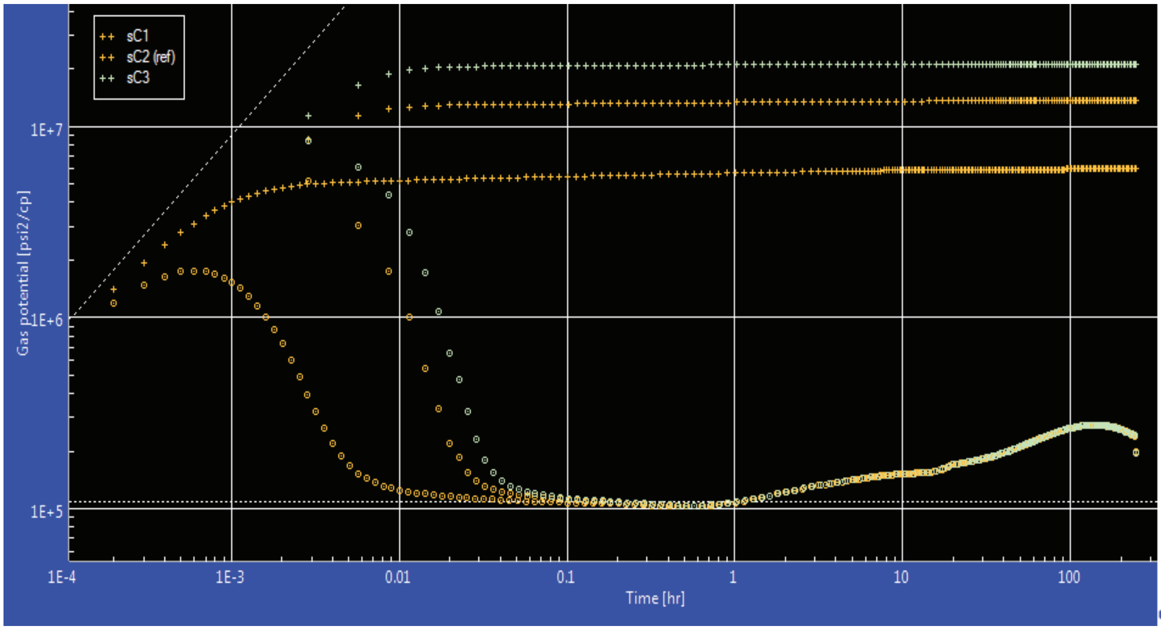


Figure 4: Log-Log plot for Scenario C: sC1 (Perm/Skin: 5400mD/17.7), sC2 (Perm/Skin: 5400mD/52.85), sC3 (Perm/Skin: 5400mD/88)

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
A1	24	4	4	4	4	48	88
A2	24	4	4	4	4	48	88
A3	24	4	4	4	4	48	88
B1	24	4	4	4	4	8	48
B2	24	4	4	4	4	8	48
B3	24	4	4	4	4	8	48
C1	24	4	4	4	4	2	42
C2	24	4	4	4	4	2	42
C3	24	4	4	4	4	2	42

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 as detailed in the Table 6 below.

Table 6: Optimal Test Timing

Scenario	Initial Buildup (Pre Test) hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
A1	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 NRV.
- Pressure and function test CT.
- RIH CT to 5 feet above TD (10,603 ftah) while pumping KCl to displace Thixsal mud.
- Confirm ceramic flapper at 9747 ftah is completely broken and no any other restriction though the EGP
- At TD, switch over to 10% HCl acid, make three passes across the screen and allow to soak for 30 mins.
- 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 R nipple (10,166 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.
- Neutralize acid in flow back tank using soda ash (K-35) before dumping.
- Bean-up must be done gradually to achieve good bridging behind EGP.
- 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 90% 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.

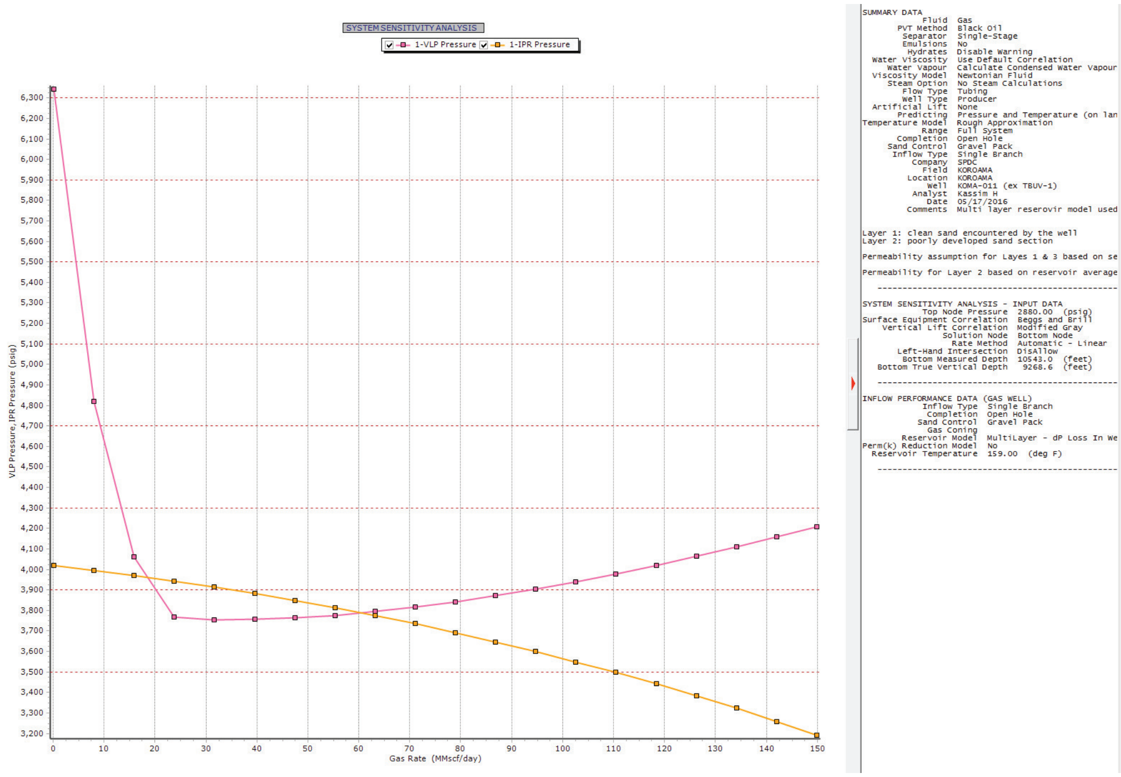
APPENDIX 1: RESERVOIR & COMPLETION DATA

Target Reservoir	D7000X
1. Casing size and Type	9-$^5/_8$''/Production casing
2. Casing Setting Depth (ftah)	10,545
3. Top of Sand [ftss/ftah]	9,197/ 10,542
4. Gross Sand Thickness (Gross) penetrated by Koroama-005 (ft tv)	65
5. Well TD (ftss/ftah)	9,250/ 10,603
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	9,199 – 9,250 9,271 – 9,322 10,545 – 10,603
7. Length of Completion Interval (ftah)	58
8. a) Top of competent cement (ftah) b) Source of data	6,153 CBL
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 44.53 deg @ 9,164
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)	4,022 9,197 4,022 159 9,197 4,022
12. Did RCI indicate abnormal pressures?	No
13. Pressure gradient @ top of sand (psi/ft)	0.44
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)	No (estimated) 9,335 (GDT 9,295 ftss) 0
16. Distance between lowest completion interval and estimated GOC in well / reservoir (ftss)	45/85
17. Is there a barrier between lowest completion interval and the present estimated GWC?	Yes (GDT at well position)
18. Gas S.G. (air=1)	0.61
19. Condensate gravity (API)	40
20. Expected FTHP (psia)*	2,880
21. Expected CITHP (psia)	3,200
22. Expected Drawdown (psi)*	234
23. Expected PI (scf/d/psi^2)*	90.1
24. Is sand exclusion installed?	Yes EGP

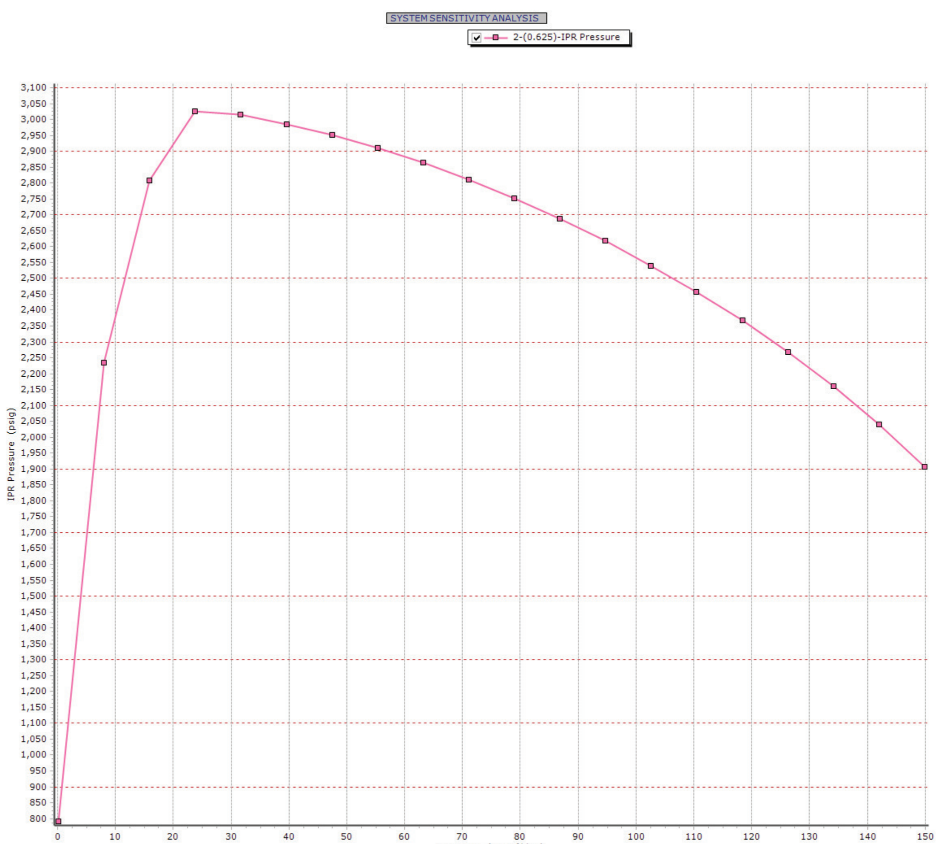
*Values are at well potential of 60 MMscf/d

APPENDIX 2: WELL PERFORMANCE PLOTS

KOMA-7 MRT Well Performance



KOMA-011 P-Q Curve.



APPENDIX 3A: CRITICAL WELL TEST OPERATIONS RISKS/MITIGATION

Risk/Description	Consequence	Likelihood / Impact (L/M/H)	Mitigation
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	L/M	Ensure the dimensions of the tools to be RIH are appropriately sized for 3-1/2" tubing accessories/profiles ID
Emergency to spill, loss of containment	Loss of order, injury, fatality, loss of equipment	L/H	Ensure presence of 3-barriers at all time during clean-up/MRT operations. Also ensure all HAZID actions are closed-out prior to commencing operation
Hydrocarbon under pressure from kick or blowout	Explosion, loss of containment, injury, fatality and environmental pollution	L/H	Check integrity of the valves on the wellhead and WRSCSSV are integrity. Install surface readout gauges to monitor pressures and ensure BOP for the coil tubing unit is fully functional
Corrosive cleaning chemicals	Corrosion, environmental contamination.	L/H	Confirm that Nitrogen for lifting is tolerated by tubing/casing material.
Failure of Downhole Shut-in Tool	In-accurate estimate of wellbore storage, impact on well test results	M/M	Ensure tool is checked at the contractor's base and confirmed operational before deploying

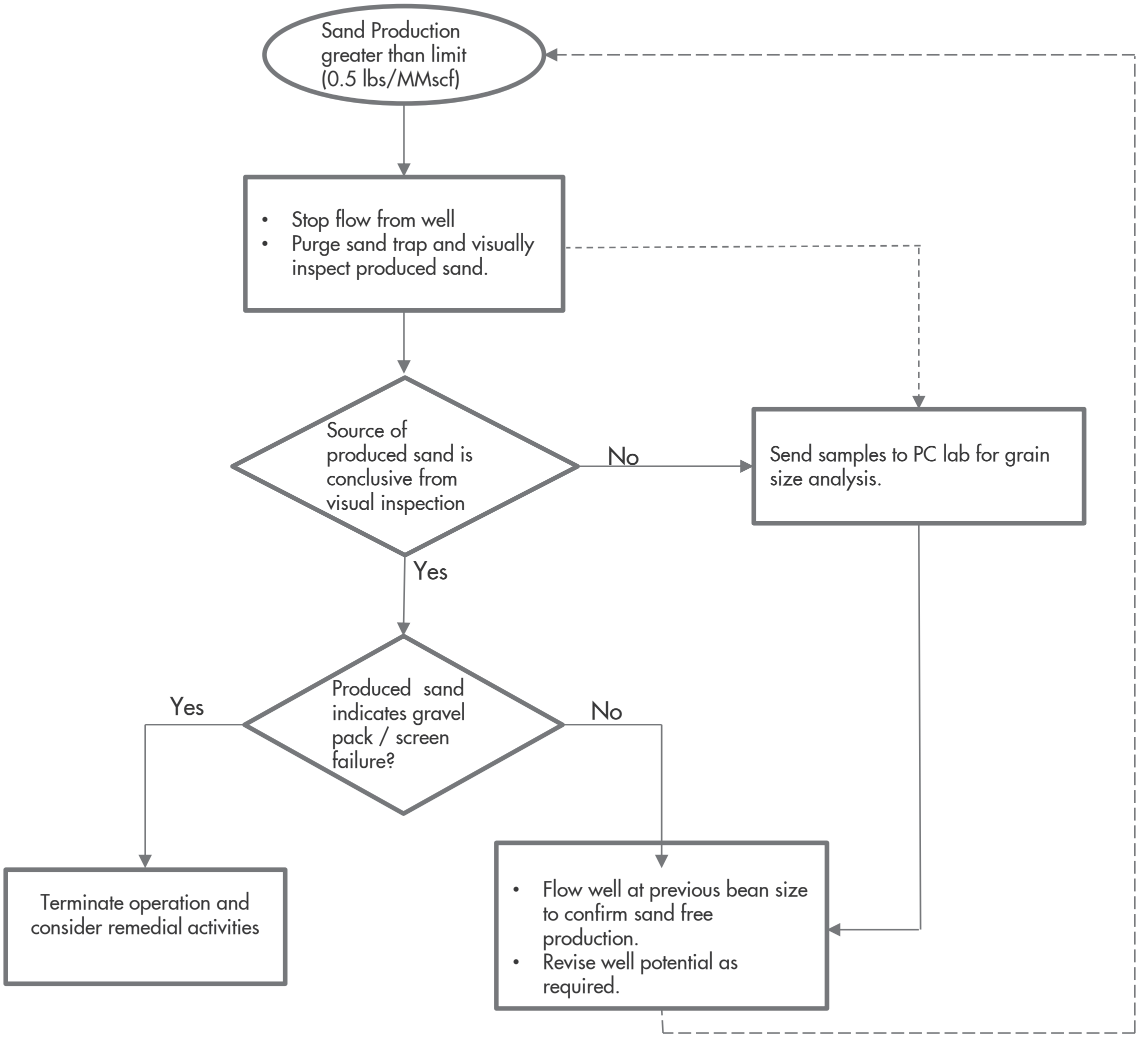
APPENDIX 3B: GAS WELL TEST RISKS/MITIGATION

Risk	Consequence	Mitigation
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Glycol will be injected at low gas rates to combat possible hydrate formation. At gas high rates, tubing temperatures are high enough to combat hydrate.
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.	13%Cr, completion material eliminates the need for corrosion inhibitor injection. Also wellhead have stainless steel clads.
Fire Source	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.
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 equipment.	Presence of 3-barrier containment Emergency Shut 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

APPENDIX 3C: 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 is 3,150 psia (ref KOMA-11 PPP –April 2016) Note: No drilling activity would be carried out during the operation	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 KOMA007 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 200 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 OHGP installed for sand control. Sand monitoring would be in place during this clean-up and MRT.	PT

APPENDIX 3D: Koroama-011 Sand production contingency plan



APPENDIX 4: Koroama-011 Final Completion Status Diagram

KOROAMA 11 FINAL COMPLETION SCHEMATIC

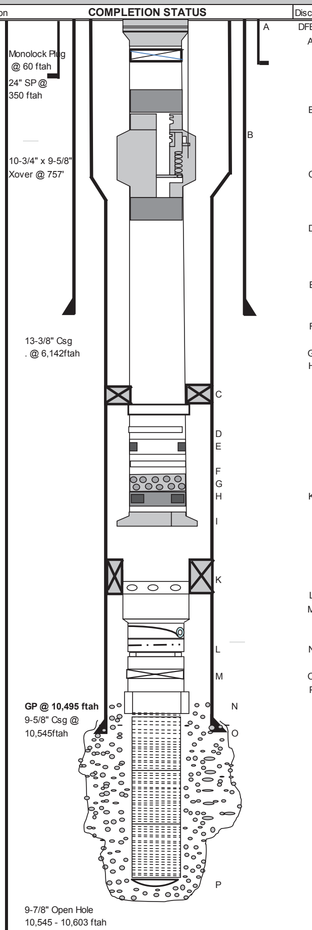
27-May-16

CASING							WELLHEAD			
SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn		ITEM	TYPE	SIZE	WP
24"	Stove Pipe		350	Driven	GX	Stovepipe	XMAS TREE		7-1/16" x 13-5/8" Flange block x 7-1/16" outlet	5,000 psi
							TREE CAP		7-1/16" c/w 7.060" Bore	5,000 psi
13-3/8"	J55	68	5,545.00	Class G	BTC	Surf Csg	GATE VALVE		7-1/16" c/w 7.060" Bore	5,000 psi
							ACTUATOR VALVE		7-1/16" c/w 7.060" Bore	5,000 psi
10-3/4"	C90	61	757	Class G	SLX	Prod Csg	TUBING HANGER	Cameron	13-5/8" Nom X 7" w/CL Prep and optic fibre	5,000 psi
							COMPACT HOUSING	Cameron	13-5/8"	5,000 psi
9-5/8"	N80	47	9,545	Class G	SLX	Prod Csg	GATE VALVE	Cameron	2-1/16" c/w 2.060" Bore	5,000 psi

TUBING								
STRING	SIZE	WT.	GRAD.	TYPE	MAX Deviation: 35.96 deg at 5,698ftah	HOLE	DESCRIPTION	RESERVOIR
					RT - Top XMT = xx ft	9-7/8"	EGP	D8200 @ 10542 ftah top
SSS	7"	29#	13Cr	HYDRIL 563	DFE (RT - Compact Housing)= 35ft			
					XMT = xxft	Drill-in Fluid Type / Properties	Thixal Mud = 0.51 - 0.52 psi.ft, YP 20 -25 lb/100 ft2 & POBM= 0.54 psi.ft	
						Completion Fluid Type / Properties:	Filtered Inhibited NaCl Brine = 0.48psi/ft	
						Workover Fluid Type / Properties:		

Sand/ Deviation | COMPLETION STATUS

D8200

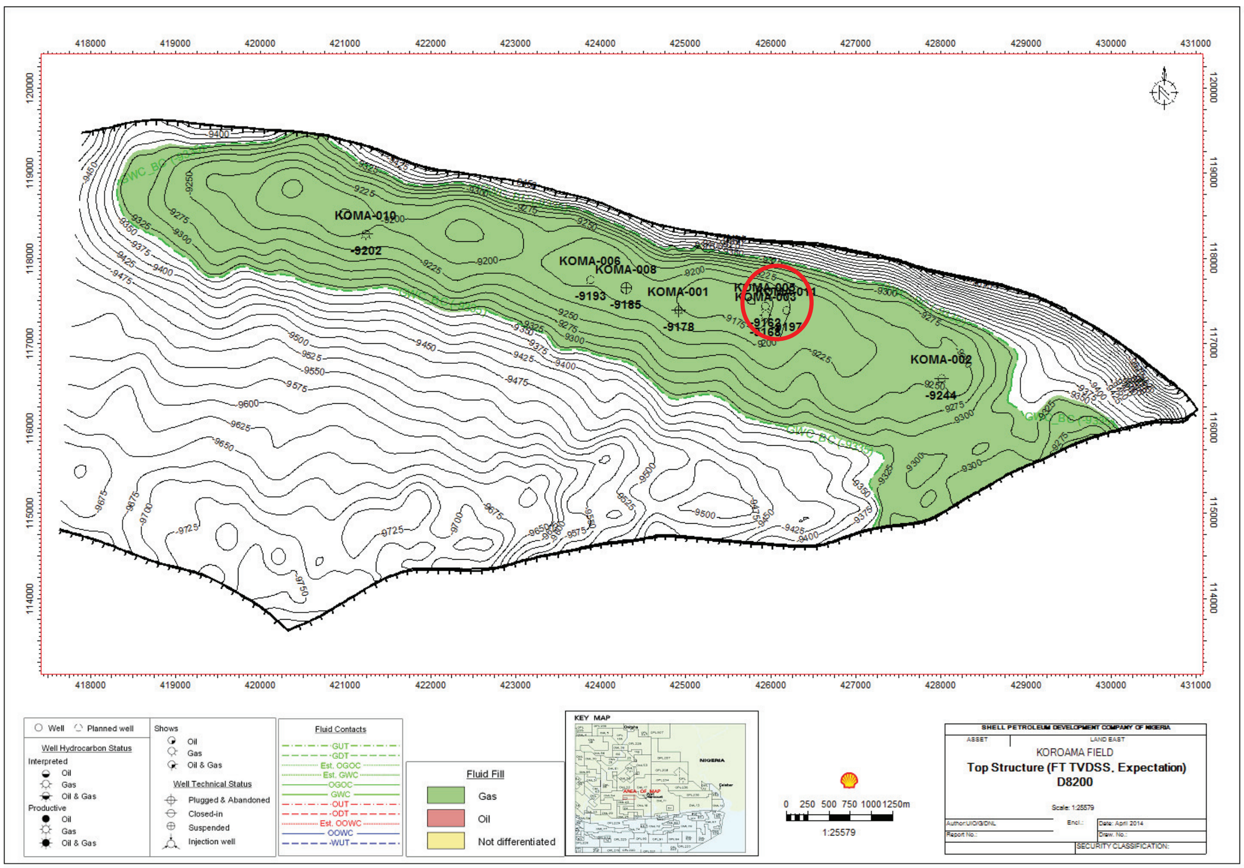


7" Completion Production String

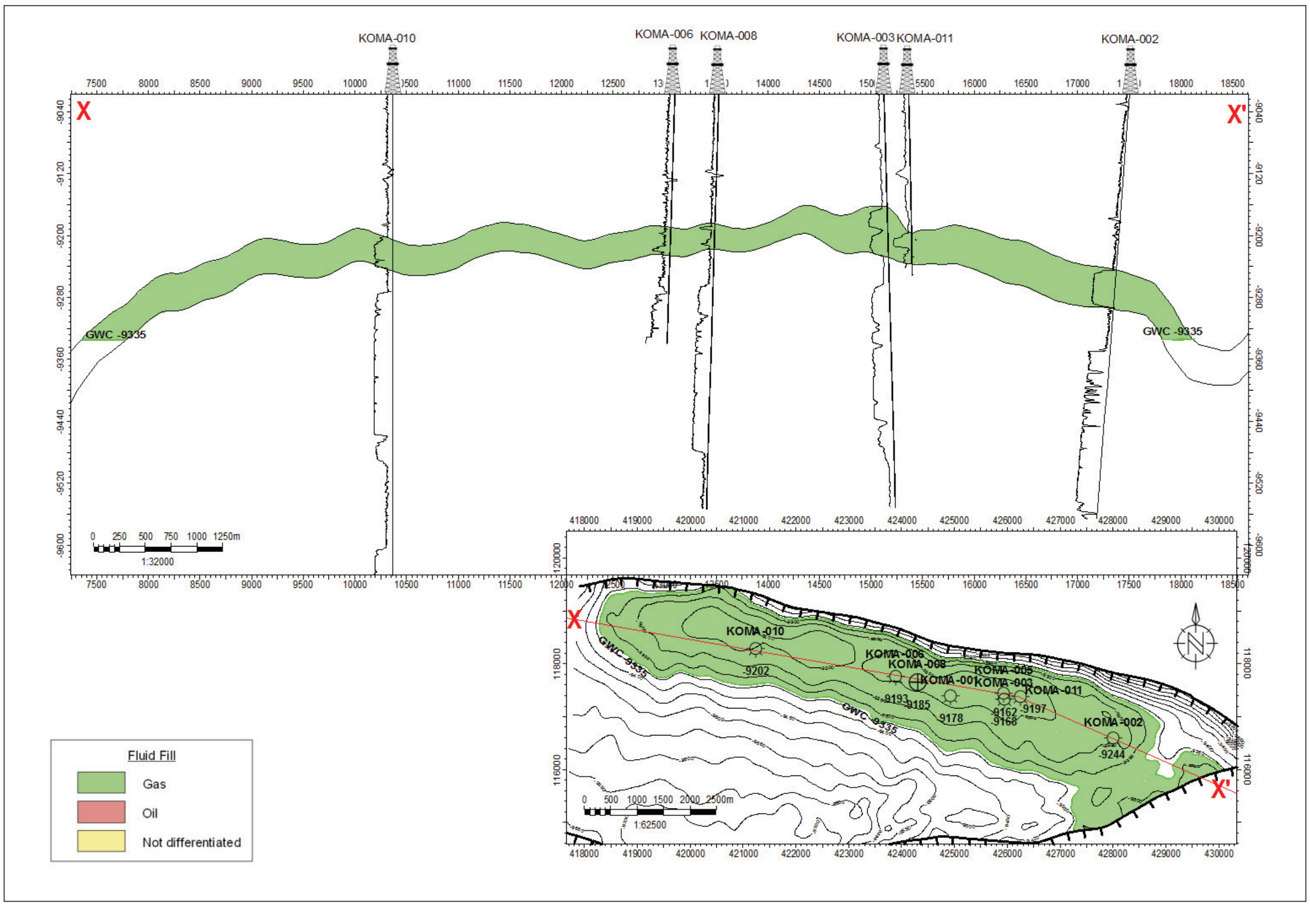
Disc	Top Depth	Length	O.D.	I.D.	DESCRIPTION
DFE	0.00	34.66			**ELEVATION**
A	34.66	**1.01**	**13.32**	**6.184**	**Cameron SSMC Hanger, 7" H563 B, 13Cr. RIGHT HAND RELEASE**
	35.67	5.51	7.660	6.179	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
	41.18	126.09	7.670	6.190	Tubing Joints, 7" 29# 13Cr L80 H563 Box x Pin
	167.27	9.83	7.670	6.190	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
	177.10	**9.70**	**7.670**	**6.120**	**Flow Coupling; 7" 13Cr L80 H563 Box x Pin**
B	186.80	**11.91**	**8.380**	**5.875**	**HES SP TRSV(Non Equalizing) 7", 29 # 13Cr H563 Box x Pin**
	198.71	9.35	7.670	6.122	**Flow Coupling; 7" 13Cr L80 H563 Box x Pin**
	208.06	6.26	7.670	6.197	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
	214.32	9,878.16	7.670	6.170	Tubing Joint, 7" 29# 13Cr H563 Box x Pin
	10,092.48	9.76	7.670	6.170	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
C	**10,102.24**	**5.75**	**8.220**	**5.870**	**HES THT Packer 9-5/8", 47-58.4#: 7" 29# 13Cr H563 Box x Pin**
	10,107.99	5.75	7.670	6.200	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
	10,113.74	42.02	7.670	6.190	Tubing Joint, 7" 29# 13Cr L80 H563 Box x Pin
	10,155.76	10.22	7.670	6.170	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
D	**10,165.98**	**1.71**	**7.660**	**5.625**	**HES R Nipple,5.625" 7" 29# 13Cr H563 Box x Pin**
	10,167.69	6.26	7.670	6.170	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
	10,173.95	41.65	7.670	6.190	Tubing Joint, 7" 29# 13Cr L80 H563 Box x Pin
	10,215.60	9.82	7.680	6.160	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
E	**10,225.42**	**2.55**	**8.260**	**6.080**	**HES Auto-Fill Sub: 7", 29# 13Cr H563 Box x Pin**
	10,227.97	6.26	7.68	6.160	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
	10,234.23	10.10	7.68	6.160	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
F	**10,244.33**	**5.17**	**8.260**	**6.080**	**HES Mirage Plug: 7", 29# 13Cr H563 Box x Pin**
	10,249.50	6.00	7.690	6.18	Pup Joint, 7" 29# 13Cr L80 H563 Box x Pin
G	**10,255.50**	**39.04**	**7.690**	**6.184**	**Perforated Tubing, 7" 29# 13Cr H563 Box x Pin**
H	**10,294.54**	**2.21**	**7.676**	**5.500**	**RN Landing-Nipple 5.625, 7" 29# H563, Box x Pin 13Cr, NO-GO = 5.500"**
	10,296.75	4.74	7.690	6.184	Pup Joint, 7" 29# 13Cr H563 Box x Pin
I	**10,301.49**	**0.84**	**8.310**	**6.450**	**Wireline Re-entry Guide, 7" 29# 13Cr H563 Box**
	10,302.33				
	10,339.97				
K	10,339.97	**7.88**	**8.434**	**6.000**	**VGP Packer, 9 5/8" 43.5-47# 6 7/8-4 AC-LH Latch Type with 7 5/8 API-STC Box**
	10,347.38	6.55	7.77	6.88	Upper Extension, 7 5/8 29.7# 13Cr STC Pin x Pin
	10,353.93	4.56	7.701	6.880	Closing Sleeve, 7 5/8 29.7# 13Cr STC-SC Box x 7 5/8 39# AB-HD-L Pin
	10,358.49	21.64	8.108	6.000	Mid Extension 7 5/8-39# 13Cr AB-HD-L Box x Pin
	10,380.13	1.75	7.674	5.812	Indicator Coupling 7 5/8" 39# AB-HD-L Box x Pin
	10,381.88	9.63	7.692	6.646	Lower Extension,7 5/8" 39# 13Cr AB HD-L Box x Pin
	10,391.51	1.13	8.139	6.270	Adapter: 7 5/8" 39# AB HD-L Box x 7" 26#,13Cr BTC Pin
L	10,392.64	2.97	8.121	5.009	**Ceramic Flapper Valve,7" 26# 13Cr API-BTC Box x Pin**
M	10,395.61	2.05	7.668	5.052	**Shear Out Safety Joint,7" 26# x 6-5/8" 13Cr, L-80 BTC Box x Pin**
	10,397.66	0.96	7.426	4.882	Adapter, 6 5/8" 28# BTC Box x 5 1/2" 20# LTC Pin,13Cr (S/N: 102197165)
	10,398.62	40.42	8.250	4.694	BLANK, 5 1/2 20# API-LC, HAL, L-80 13Cr, 480 - SPIROLIZER
N	10,439.04	40.41	8.250	4.694	BLANK, 5 1/2 20# API-LC, HAL, L-80 13Cr, 480 - SPIROLIZER
	10,479.45	40.53	8.250	4.694	BLANK, 5 1/2 20# API-LC, HAL, L-80 13Cr, 480 - SPIROLIZER
O	10,519.98	81.05	8.250	4.778	Poromax Screen: 5 1/2" 20# API-LTC B x P,13Cr 250 Micron
P	10,601.03	0.97	6.130	N/A	Bull Plug, 5 1/2" 24# LTC Box,13Cr
	10,602.00				

TD (ftah):	AUTHOR:	DATE COMPLETED:	DRAWN BY:	CHECKED BY:	APPROVED BY:
	PTW/O/NG		Justus Ngerebara		

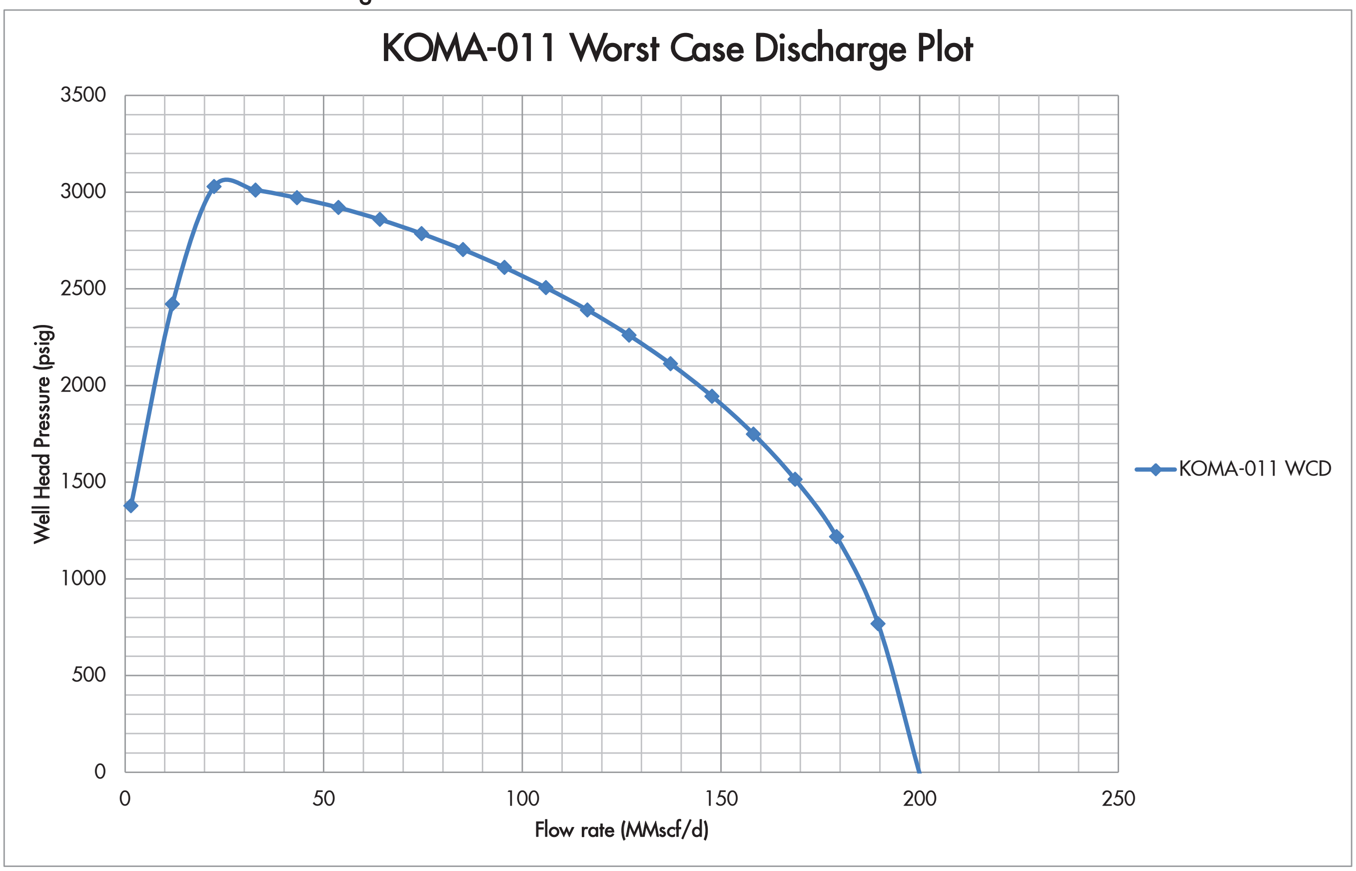
APPENDIX 5: Top Depth Map of the KOMA-011 D8200X sand



APPENDIX 6: Cross section along KOMA-007 well path



APPENDIX 7: Worst Case Discharge Plot

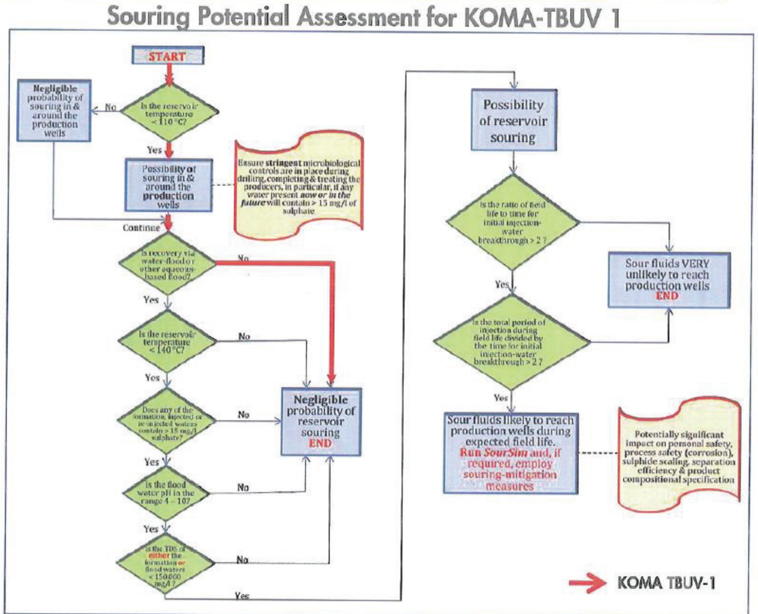


APPENDIX 7: KOMA-011 (ex TBUV-1) H2S Prediction

KOMA TBUV-1 H_2S PREDICTION

- PVT analysis not available for D8200 reservoir, however available PVT data for C9400, D6000, E7000& F1000 reservoirs indicate no presence of H_2S
- D7000, E1000 and F1000 reservoirs are currently producing with no H_2S production recorded.
- Naturally occurring H_2S concentration is therefore predicted to be 0%mol
- Expected Reservoir Temperature = 66 ºC (150ºF) 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 KOMA-TBUV 1



Prepared by:	Kassim, Hamzat	Nnadi Magnus	Date: 3/29/2016
Checked by:	Essien, Uwem	Nnadi Magnus	Date: 19/03/2016
Approved by:	Nwankwo, Cosmas 23/3/2016	Ukauku, Ikwan	Date: 30/03/2016

SPDC

1

APPENDIX 8: KOMA-011 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**