DIMENSION BID

PETRONAS

DULANG D-22
SAND CLEANOUT

Revision: 4
Prepared for: Pravin Nair Venugopalan
Date Prepared: 4th April 2024
Well: D-22
Field: Dulang D
Operation Region: PMA
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DESIGN VERIFICATION

PREPARED BY DB CTS Field Engineer	 Muhd Ameerul Zaeem	04/04/2024 Date
REVIEWED BY DB CTS Technical Advisor	 Kung Yee Han	04/04/2024 Date
APPROVED BY DB CTS General Manager	 Aliff Adenan	04/04/2024 Date
APPROVED BY PCSB Dulang Well Intervention Engineer	Pravin Nair Venugopalan	Date
APPROVED BY PCSB Technical Professional Well Intervention, PMA	M Izwan B A Jalil	Date
APPROVED BY PCSB Head of Cluster 2 Well Intervention, PMA	Ahmad Hafizi B Ahmad Zaini	Date

Remark: Do not execute the procedures in this document if it is not fully approved and signed by all parties.

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REVISION HISTORY

Rev. No	Section	Date	Revised By
0	All	10/3/2024	M. Ameerul Zaeem
1	Changes made on BHA for Contingency Run	13/3/2024	M. Ameerul Zaeem
2	To add additional CT run for Physical Tag 'D' Nogo Nipple & CT Set Widepak Plug at 2,200 m MDTHF	26/3/2024	M. Ameerul Zaeem
3	To change BHA configuration for CT Run#2	31/3/2024	M. Ameerul Zaeem
4	To change BHA configuration for CT Run#2 & setting depth of Widepak Plug to 2,230 m MDTHF	4/4/2024	M. Ameerul Zaeem

ACRONYM

Acronym	Abbreviation
BHA	Bottom Hole Assembly
RIH	Run In Hole
POOH	Pull Out of Hole
HUD	Hang Up Depth
TCC	Tubing Clearance Check
SCO	Sand Clean Out
TIT	Tubing Integrity Test

BOP	Blow Out Preventer
CT	Coiled Tubing
ID	Internal Diameter
MDTHF	Measure Depth Tubing Head Flange
TOP	Top of Plug
MASTP	Maximum Allowable Surface Treating Pressure
STP	Surface Treating Pressure

TABLE OF CONTENT

OBJECTIVES

The objective of this job is to perform sand cleanout and clear HUD (sand & sludge) inside completion tubing until EOT at 2,248 m MDTHF

Therefore, this CTU operation consists of 3 CT runs with 1 contingency (CT Spot Acid on top of TRSV).

BACKGROUND

Dulang D-22 is a Single WAG Injector Well with 3-1/2" completion which was completed on August 1996 with maximum deviation of 78.3 degree at 1,137.3 m MDTHF. Currently the well is idle due to slickline encountered HUD at 145 m MDTHF with 2.0" LIB (suspect flapper in close position). The flapper was unable to lock open due to suspect sludge plugging on top of flapper. PCSB has engaged DB to perform Sand Cleanout from latest HUD at 145 m MDTHF until EOT at 2,248 m MDTHF prior to Plug & Abandonment (P&A) activity.

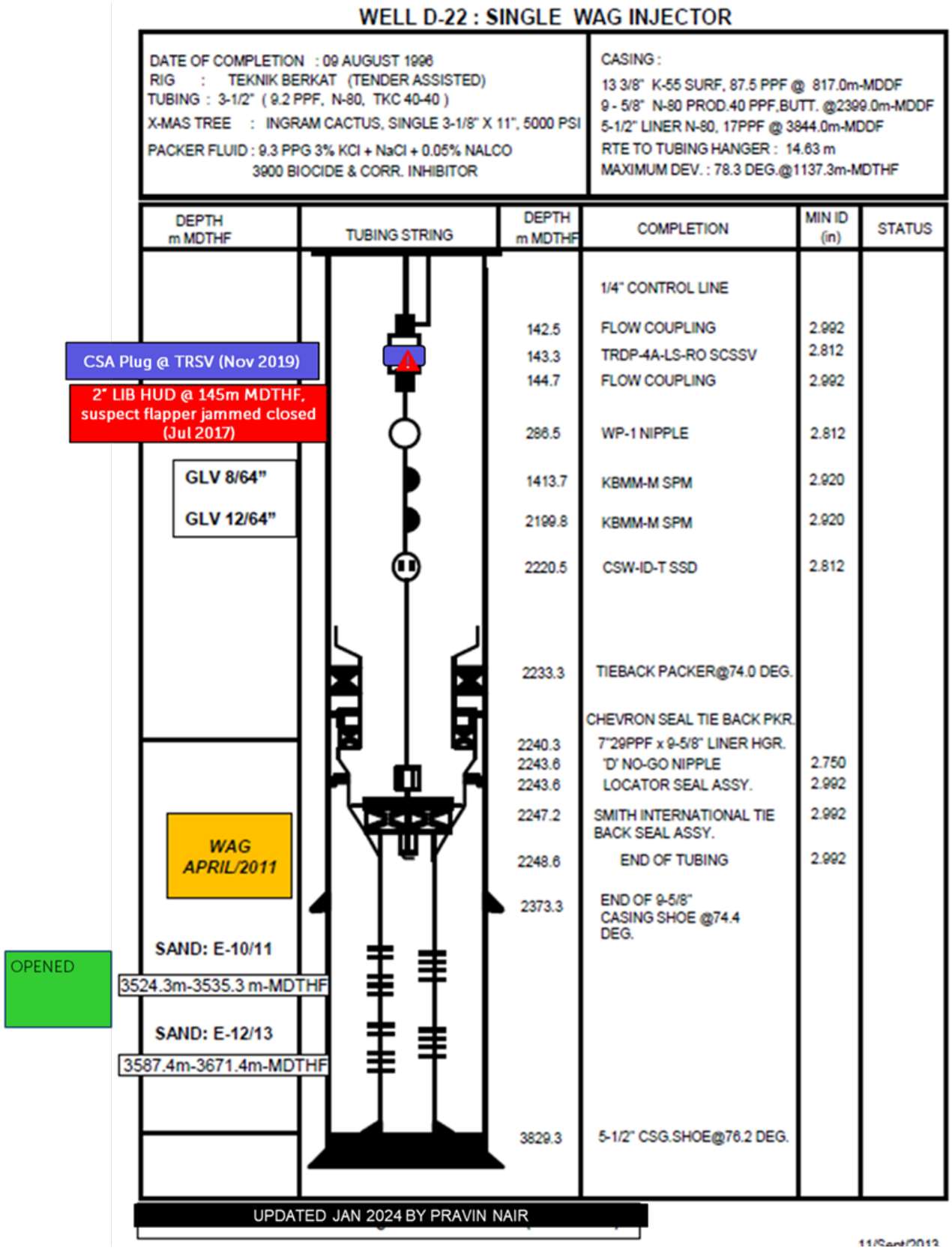
WELL DATA

Input Parameter	Parameter Value
Field	Dulang D-22
Max. Deviation (degrees)	78.3 Deg @ 1,137 m MDTHF
Min. Restriction (inch)	2.75" ('D' Nogo Nipple) @ 2,243.6 m MDTHF
Tubing Specification	3-1/2" Production Tubing (Refer Well Schematic)
Type of Fluid & Density	N/A
Top of Fluid	No fluid level detected
Current Well Status	Idle
Depth of zone	E10/11 (3524.3-3535.3m MDTHF) E12/13 (3587.4-3671.4m MDTHF)
Reservoir Pressure (psi)	E10/11: 1072 (From nearby well) E12/13: 1772 (From nearby well)
Reservoir Temperature (deg F)	E10/11: 224 E12/13: 228
Porosity	E10/11: 0.2 E12/13: 0.27
Permeability (mD)	E10/11: 9.4 E12/13: 152
Fracture Gradient	0.7 psi/ft
H_2S Content	Not available
CO_2 Content	Not available
Mercury, HG	Not available
Additional Information / Notes / Special Requirement:	
• RIH 2.00" LIB to HUD @ 145m-MDTHF (Impression of flapper in close position) (July 2017) • RIH 2.72" LIB to HUD @ 145m-MDTHF (Impression of flapper) (Aug 2015) • RIH 2.25" Sand Bailer to HUD @ 145m-MDTHF (Recovered 0.2 L of sludge) (Aug 2015)	

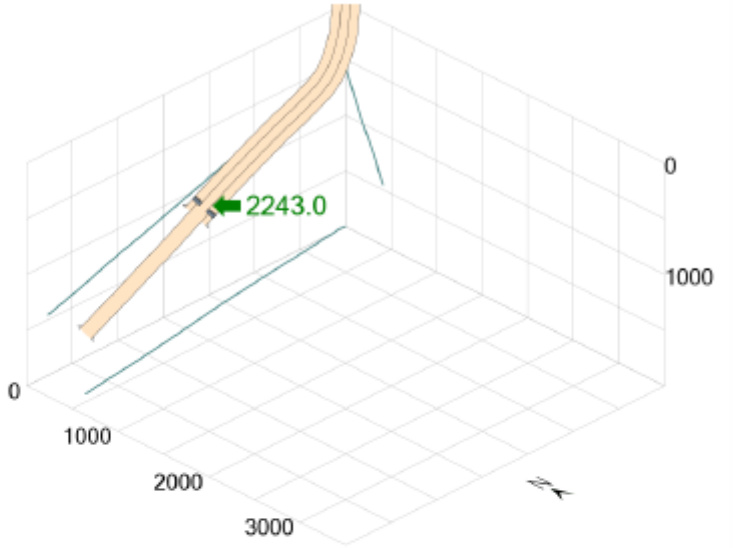
OPERATION SUMMARY

Item	*Job Description*	*Remark*
A	Slickline	1. Retrieve CSA Plug at TRSV 2. Lock Open TRSV Flapper 3. TCC
B	Coiled Tubing Operation	Contingency CT Spot Acid on TRSV Flapper
C	Slickline	1. Lock Open TRSV Flapper 2. TCC
D	Coiled Tubing Operation	CT Run#1 Sand Cleanout From HUD at 1,573 m MDTHF Until EOT at 2,248 m MDTHF
E	Slickline	TCC
F	Coiled Tubing Operation	CT Run#2 Depth Correlation & Drift Run with 2.72" FC CT Run#3 Set Widepak Plug at 2,230 m MDTHF
G	Bullheading Operation	Integrity Test (if require)

WELL DIAGRAM



WELL 3D PLOT



Well name: Dulang D22
Total depth: 3844.0 m
Max Inclination: 77.9° at 1146.8 m
Max DLS: 6.554 °/100ft at 483.2 m
Min ID: 2.992 in at surface.
WHP: 150 psi

Input Parameter	*Parameter Value*
Field	Dulang D-22
Trajectory Until Depth	3,844 m MDTHF
Max. Deviation (degrees)	77.9 degree at 1,146.8 m MDTHF
Min. Restriction (inch)	2.75” (‘D’ Nogo Nipple) @ 2,243.6 m MDTHF

TREATMENT VOLUME

Description	Details
Tubing Specification	3-1/2" 9.2ppf# N-80
Production Casing Specification	9-5/8" 40ppf# N-80
Liner Casing Specification	5-1/2" 17ppf# N-80

Dulang D-22 **Downhole Calculation** **Prepared Date: 9/3/2024**

Tubing

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
THF to TRSV	3 1/2	2.992	9.2							0.00870	14.63	143.30	48	470	**422**	**4**
TRSV to SSD#1	3 1/2	2.992	9.2							0.00870	143.30	2220.50	470	7285	**6815**	**59**
SSD#1 to EOT	3 1/2	2.992	9.2							0.00870	2220.50	2248.60	7285	7378	**92**	**1**
															TOTAL	**64**

A-Annulus (PCP)

Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
THF to SSD#1	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	14.63	2220.50	48	7285	**7237**	**463**
SSD#1 to Tie Back Seal Assy	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	2220.50	2247.20	7285	7373	**88**	**6**
															TOTAL	**468**

Wellbore Volume

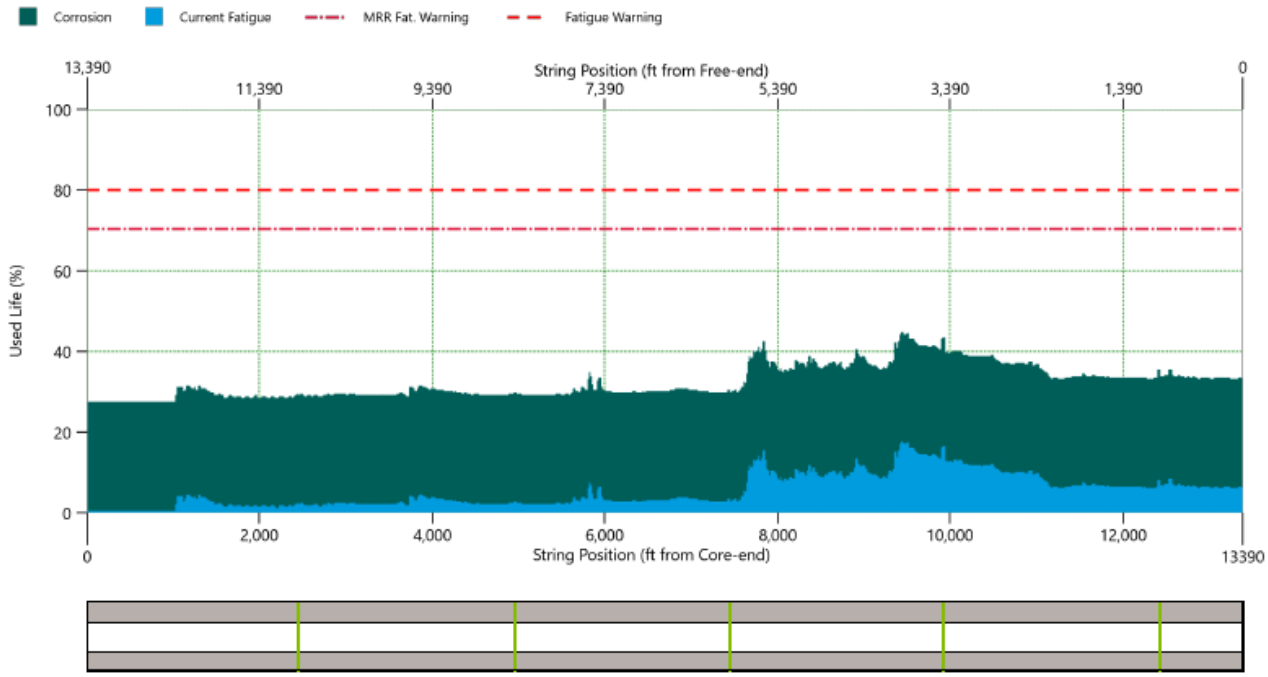
Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
Tie Back Seal Assy to PBTD	5 1/2	4.892	17							0.02325	2247.20	3829.30	7373	12564	**5191**	**121**
															TOTAL	**121**

CT STRING INFORMATION

OD (in)	Spec	W/T (in)	ID (in)	Length (ft)
1.5	HS-90	0.125	1.25	15,583
CT Volume: 20.3 bbls				

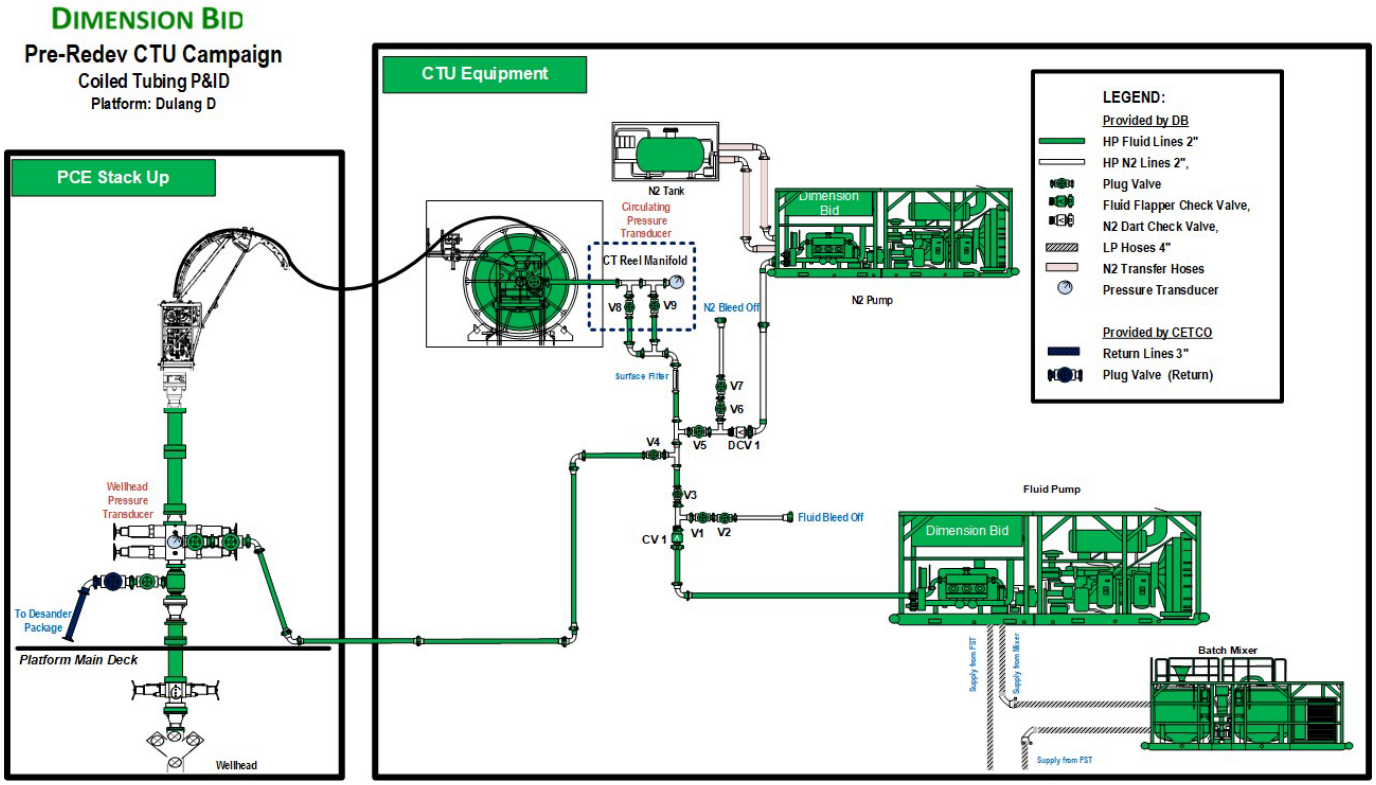
CT STRING FATIGUE

- Current **used life** for Tenaris #40416 is at **44.55%**



Run #	Date	Field Name	Well Num	Job type	Cum. Run ft	CT cut ft	New CT leng ft	Job Fatigue %	Job Corrosion %	Max Fatigue	Cum. Corrosion %	Used String Life %
N/A	26-Aug-23	Dulang-D	D-15L	Trim Coiled 57 ft	N/A	57	15,586	0	0	0	0	30.44
17	29-Aug-23	Dulang-D	D-15L	Sand Clean Out	155,003		15,586	3.2	2	3.74	17	31.4
18	1-Sep-23	Dulang-D	D-15L	Sand Clean Out	155,342		15,586	0.8	0	1.11	0	32.44
19	1-Sep-23	Dulang-D	D-15L	Sand Clean Out	161,642		15,586	5.4	2	7.13	19	33.44
N/A	8-Sep-23	Dulang-D	D-15L	Trim coiled 13ft	N/A	13	15,573	0	0	0	0	N/A
N/A	8-Oct-23	Dulang-C	C-24L	Trim coiled 51ft	N/A	51	15,522	0	0	0	0	N/A
20	11-Oct-23	Dulang-C	C-24L	Sand Clean Out	168,174		15,522	1.1	0	8.23	19	36.44
21	22-Oct-23	Dulang-C	C-24L	Acid stimulation HCL 15%	174,750		15,522		2	2.89		37.6
N/A	23-Oct-23	Dulang-C	C-24L	Trim coiled 1ft	N/A	1	15,521	N/A	N/A	N/A	N/A	N/A
22	27-Oct-23	Dulang-C	C-04s	Scale Clean out	186,519		15,521	3.28	2	21.46	21	42.46
N/A	31-Oct-23	Dulang-C	C-04s	Trim coiled 2ft	N/A	2	15,519	N/A	N/A	N/A	N/A	N/A
23	31-Oct-23	Dulang-C	C-04s	Scale Clean out	196,579		15,519	4,70	2	21.55	23	44.55
N/A	10-Nov-23	Dulang-C	C-04s	Trim coiled 30ft	N/A	30	15,489	N/A	N/A	N/A	N/A	N/A
NA	10-Mar-24	Open yard	NA	CUT COIL 2100FT	N/A	2100	13,389	0	0.5	0	N/A	N/A
NA	11-Mar-24	Open yard	NA	EMC 2	N/A	0	13,389	0	0.5	0	N/A	N/A

PROCESS FLOW DIAGRAM



SAFETY OPERATIONAL PROCEDURES

Prior to commencement of the CT / Bullheading operation, a pre-job meeting will be held. This should be attended by the following parties as a minimum:

OIM, WSS, CT Supervisor, Representatives of other service companies involved and others as necessary.

Safety meetings should be held at the start of every shift and risk assessments must be evaluated during this time. Tool box talks should be held immediately prior to the job execution.

Note: The safety meeting must be driven by DB Supervisor addressing the following topics as a minimum:

1. Muster point.
2. Take list of personnel on site (Head count)
3. All personnel should review and be familiar with escape routes and emergency procedures.
4. Describe the **job objective, fluids and volumes to be pumped, pressures expected** during the job, and others.
5. Review **Dimension Bid Operations Policy and Procedure Manual.**
   - 5.1. Ensure at all steps carried out during the operations comply with this Manual.
   - 5.2. Management of change MUST be applied any time there is a need to deviate from the steps contained this procedure.
   - 5.3. A document MUST be created describing each the step of the deviation. This document shall also include the deviation Risk Assessment and it MUST be approved and signed by PCSB – Head of Well Intervention and Dimension Bid Operations Manager.
6. Exercise Stop work authority if unsafe condition occurs and assess situation with all team members, resume operation after mitigation plan is in place.
7. Personnel responsibilities throughout the job.
8. Spills, fire, blow out, unexpected well behaviour.
9. Emergency shower station and eye wash station location.
10. Trapped potential energy such as pressure or CT stiffness.
11. Prepare related Job Hazard Analysis (JHA) prior commencement of any work, get approval from Client Site Representative (CSR) and review it with all personnel involved as well as to review Risk Assessment.
12. Discuss the well H_2S, CO_2, Hg (Mercury) content (if applicable).
13. Adhere all **PCSB Zeto Rules** and other guidelines.
14. Take a physical count of inventory and make sure all required materials are available on site.
15. **Barricade** the work area and display the appropriate **warning sign**.
16. On chemical mixing and handling; all personnel involved shall hold **safety meeting** and review **Safety Data Sheet** (SDS).
    - 16.1. Personnel involve during chemical handling shall be briefed by DB Chemical Specialist onsite and extra precautions must be taken. All SDS must be available on site and reviewed prior chemical handling.
    - 16.2. All non-essential personnel shall stay away from mixing site.
    - 16.3. Use PPE including respirators, hard hats, eye protection and steel-toed boots.
    - 16.4. Verify if there is any **dead volume** in the mixing tanks and adjust volumes to account for non-usable volume in the blender / mix tank.
    - 16.5. Consider wind direction and note all trip hazards in the mix / pumping area.

16.6. Prior to mixing chemicals, clean and verify the tank/batch mixer and lines are free of any debris and or contaminants.

16.7. In case of spill; wash the place where any chemical has been spilt with available spill kit.

16.8. Take care to prevent leakage due to ejection from valves, fittings, flanges, or other joints flexible chemical hoses and pumps. Never repair the equipment during transfer into mixing tank/container.

17. Take reading of Shut in / Flowing Tubing Head Pressure (SI/F/THP), Casing Head Pressure (CHP) and fluid sample (if available) prior to operation.
18. Check gas lift condition and capability with Site Operation Representative (SOR).
19. Ensure fitness prior to perform duties assigned.
20. Ensure all barriers are in place and followed.

HEALTH, SAFETY & ENVIRONMENT

1. Evaluate possible risks to arise during the job execution.
2. Evaluate risk assessment. Report any abnormal or insecure condition on site, taking into account all the steps or procedures to follow. Discuss with PCSB HSE coordinator, the execution or suspension of the job.
3. Review SDS of each product that will be used. Verify that all personnel on location handling toxic or corrosive products have the proper PPE.
4. Review the contingency plan for spills.
5. Do not vent / release any hydrocarbons from the well to atmosphere. Returns from the well should be handled safely by Flowback Company.
6. Prior to DB personnel walking on upper deck, DB Supervisor to inspect upper deck and ensure that the area it is in good condition (Gratings, Hatches, etc.)

EQUIPMENT RIG UP PROCEDURE

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, and personnel responsibilities, well control emergency drill and safety precautions.

1. Spot the equipment accordingly to space availability, ensure reel position is aligned with the well.
2. Spot jacking frame at available space with sufficient height and crane capacity to rig up the injector head and gooseneck.
3. Rig up the 4” LP hoses from fluid storage tanks to batch mixer and single pump unit
4. Rig up 2” HP treating line as per DB Technical Standard from single pump unit and N2 converter unit to CT reel manifold. Include bleed off line on both lines as well.
5. Install correct wellhead crossover on the wellhead. Ensure well is fully secure and record the MV and CV turns.
6. Install Blowout Preventer (BOPs):
    6.1. Rig up Single BOP with necessary length of risers on top of the wellhead crossover.
    6.2. Rig up Combi BOP with flow tee above the risers
    6.3. Hook up BOP hoses and conduct function test for each ram.
7. Rig up 2” kill line from single pump unit line to BOP kill port
8. Rig up flow back line from flow tee to Choke manifold -> desander unit -> High pressure flowback pump -> Donor Well
9. Spot injector head assembly (c/w stripper) with jacking frame on top of wellhead area. Ensure the gooseneck is aligned with the reel position
10. Inspect the chain and gripper block condition and ensure the alignment is correct
11. Rig up the following hydraulic hoses:
    11.1. From CT Power Pack to CT Control Cabin
    11.2. From CT Power Pack to CT Injector hose reel
    11.3. From CT Control Cabin to CT Reel
    11.4. From CT Control Cabin to CT BOPs
    11.5. From CT Power Pack to Jacking Frame
12. Perform EMC 1 for all equipment. Start up and run all equipment for few minutes.
13. Jack up CT control cabin.
14. Function test both BOP rams.

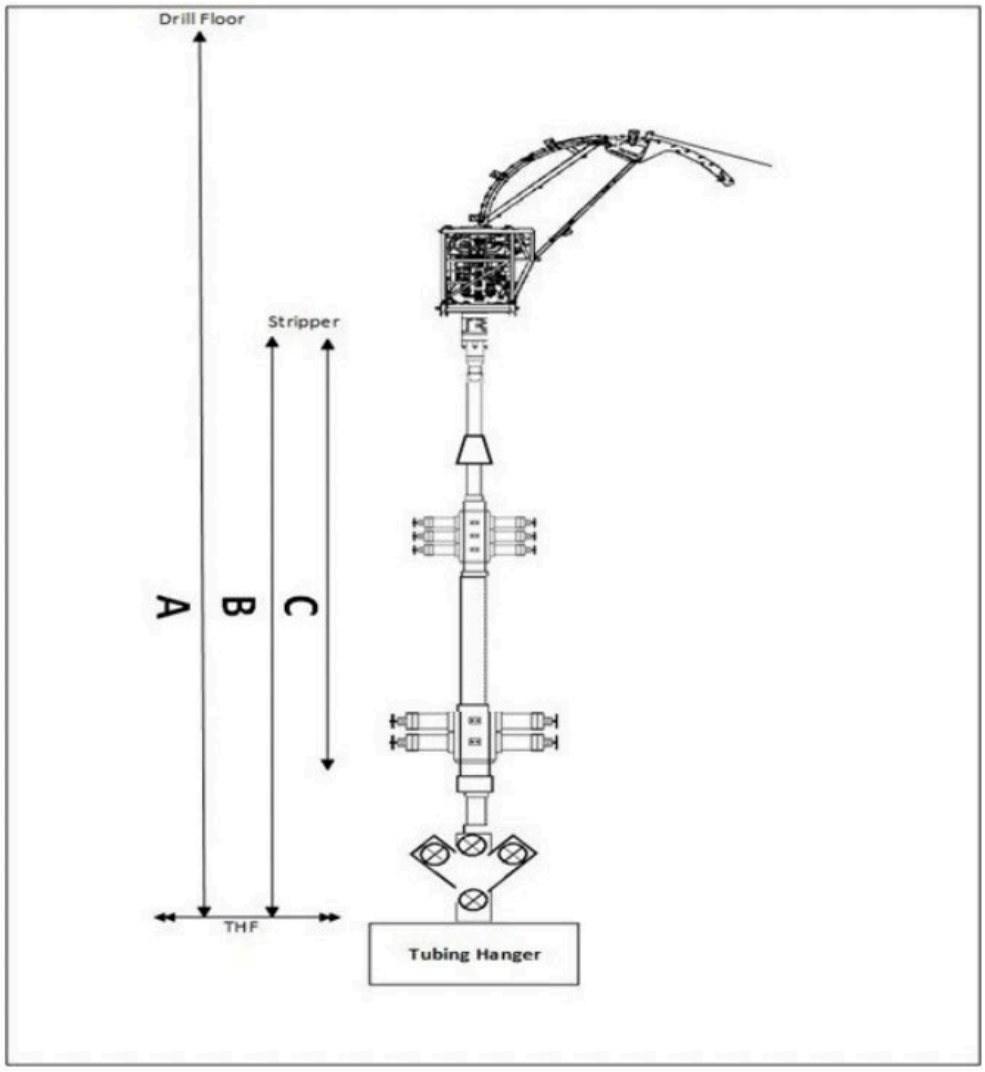
    *Observe indicator pin to confirm that all rams are in good working condition.

15. Install the stab-in-guide on the CT then stab the string into injector head.
16. Record the total cut length of CT String in Cerberus and Pipe Management for future reference.
17. Make up the CT connector and perform pull test at least 15,000 lbs as per DB SOP. This test to be recorded in OrionNET.

    *Do not perform pull test more than 80% from CT Limit.

18. Install pressure test plate onto the CT connector.
19. Circulate the string with water until clean return is seen prior to proceed with pressure test CT Connector.
20. Pressure up the CT string to 5,000 psi gradually by 500 psi increment then hold for 10 minutes.

21. Open the needle valve to release the pressure slowly.
22. Make up the BHA onto the string as per BHA diagram provided.
23. Use the jacking frame to pick up the injector and risers then connect to the Combi BOP. Secure down the injector assembly with chains.
24. Measure the following length to set the CT depth:



Distance	Length (ft)
A: Tubing Hanger (THF) to RKB	
B: Tubing Hanger (THF) to Stripper	
C: BHA Length	

25. Pick up CT and tag the stripper to set CT depth based on this calculation “A-B+C”.

Ensure to cut sufficient CT String length in order to shift fatigue after every three (3) CT run.

EQUIPMENT PRESSURE TESTING PROCEDURE

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, and personnel responsibilities, well control emergency drill and safety precautions. Refer the following procedure to pressure test BOP Body, Blind Ram, Surface Line and Wellhead connection.

1. Isolate the line to CT. Double confirm the valve is closed.
2. Fill and pressure test the treating line with water to 500 psi and hold for 5 minutes. Inspect the lines for leaks and observe for any pressure drop.
3. Increase pressure to 3,000 psi and hold for 10 minutes. Inspect the lines for leaks and observe for any pressure drop.
4. Fill the pressure control equipment and ensure air is vented from the system by leaving the blind ram and blind ram equalizing valves open.
5. Close blind ram and equalizing valve. Pressure up the surface lines, BOP body, blind rams and wellhead connection to 500 psi then increase gradually to 3,000 psi through the kill line, hold for 10 minutes. Inspect the lines for leaks and observe for any pressure drop.
6. Once test complete, open blind ram pressure equalizing port then bleed off any residual pressure and open the blind rams.

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, and personnel responsibilities, well control emergency drill and safety precautions. Refer the following procedure to pressure test BOP Body, Blind Ram, Surface Line and Wellhead connection.

1. Fill up the CT string and stack up until leak can be seen at stripper.
2. Energize the stripper and begin pressure test the complete stack up (CT string, stripper, CT stack and risers) to 5,000 psi against Crown Valve, hold for 10 minutes.
3. Bleed off pressure inside stack up to 1,500psi and bleed off pressure inside CT to 0psi immediately to test the Double Flapper Check Valve with DP of 1,500psi and hold for 10 minutes.
4. Bleed off the pressure from BOP kill port side.

   *Step 4-8 can be neglected if pipe ram has been pressure tested prior to the job.

5. Place CT string across pipe ram then close the ram.
6. Open pipe ram equalizing valve then fill up the BOP slowly.
7. Close the equalizing valve and begin pressure test the pipe ram to 3,000 psi, hold for 10 minutes.
8. When the tests are complete, bleed off the pressure.

OPERATIONAL PROCEDURE

All depths specified below are in m-MDTHF.

CT CONTINGENCY#1: SPOT ACID ON TRSV FLAPPER

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, personnel responsibilities, emergency well control drill, and safety precautions.

1. Prepare 100bbls of Treated Injection Water, TIW as per recipe below:

Treated Injection Water (TIW)				**100**	**BBL**	***Description***
Seq.	***Product***	***Concentration***		***Volume***		
1	Injection Water	994	gptg	4,175	gal	Base Fluid
2	ACM H2S Clear 200	2	gptg	8	gal	CO2 & H2S Corrosion Inhibitor
3	ACM BACT 200	2	gptg	8	gal	Micro Biocide Control
4	ACM OXYFREE 100	2	gptg	8	gal	Oxygen Scavenger

Mixing Instruction:
a) Prepare Injection Water into the mixing tank.
b) Add ACM H2S Clear 200 into the tank and circulate the mixture.
c) Add ACM BACT 200 & ACM OXYFREE 100 into the tank and circulate the mixture until homogenous.

Note: The above recipe is for 100bbls of TIW. Please prepare another batch of Treated Injection Water once needed.

2. Prepare 50bbls of D801 Cleanout Gel as per recipe below:

D801 Cleanout Gel				**50**	**BBL**	***Description***
Seq.	***Product***	***Concentration***		***Volume***		
1	Injection Water	992	gptg	2,083	gal	Base Fluid
2	D801 Gel	40.5	pptg	85	lbs	Gelling Agent

Mixing Instruction:
1. Prepare Injection water in the mixing tank.
2. Add D801 Gel into the tank and circulate the mixture until homogenous.

Note: The above recipe is for 50bbls of gel. Please prepare another batch of gel once needed.

3. Rig up CT unit and surface line on Dulang-D platform as per Site Visit Report:

3.1. Review JHA and risk assessment with all personnel involve in the rig up operation. Please send a copy of JHA to Engineer in Charge.

3.2. Lift up CT unit using crane and spot on platform.

3.3. Rig up CT package and surface treating line.

3.4. Rig up 2” kill line to BOP kill port.

3.5. Rig up 2” flexible hose from pumping tee.

3.6. Make up the **CT End Connector**.

3.7. Install the Pull and Pressure Test Sub.

3.8. Perform Pull Test on the CT End Connector **to 15,000 lbf** and record this in OrionNET.

Note: Do not perform pull test more than 80% coil limit. Consult with town if require.

3.9. Perform Pressure Test on CT End Connector. Pumping treated injection water through the CT, apply low pressure test of **300 psi for 5 minutes** and high-pressure test of **5,000 psi for 15 minutes** after stabilization. Record the pressure test.

3.9.1. **For low pressure:** Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 270 psi) over 5-minutes test interval after the pressure stabilizes.

3.9.2. **For high pressure:** Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 4,500 psi) over the 15- minutes test interval after the pressure stabilizes.

4. Make up 1.5" Cleanout Nozzle tool (Slim BHA) as per **BHA#1: 1.5" Cleanout Nozzle BHA** in **Appendix 1**.

   NOTE: Take the below measurement and record in the DOR.

5. Perform function test of the Cleanout Nozzle to determine the pumping parameter. Record the data in the table below, do not exceed 5,000psi.

Flow Rates (bpm)	N2 Rates (scfm)	Pressure (psi)	Remark
0.3			
0.5			
0.7			
0.8			
0.9			
1.0			
1.1			
1.2			
1.3			

6. Box up to connect the riser and prepare for pressure test.
7. Pick up CT and tag BHA with the stripper.
8. CT stack up pressure test against Wellhead Crown valve. Pumping treated injection water through the CT, apply low pressure test of **300 psi for 5 minutes** and high-pressure test of **3,000 psi for 15 minutes** after stabilization. Record the pressure test. Record test on a chart. Upon successful pressure test, bleed off pressure via Pump-In Sub.

   8.1. For low pressure:

   Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 270 psi) over 5-minutes test interval after the pressure stabilizes.

   8.2. For high pressure:

   Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 4,500 psi) over the 15- minutes test interval after the pressure stabilizes.

9. Pressure tests the BHA Check Valve. With **3,000 psi** in the CT stack up, bleed off the stack up pressure to **1,500 psi** via pump-in sub; and bleed off pressure in the CT to zero (0) psi via reel manifold.

   9.1. Acceptance criteria: **Pressure drop is less than 10% (above 1,350 psi) over the 15- minute test interval after the pressure stabilizes.** Observe for any pressure changes in the stack up. If the BHA check valve is not holding, proceed to replace the MHA; do not RIH with leaking check valve; repeat steps 8 and 9.

10. Upon successful test, bleed off the pressure in the CT stack up to zero through the pump-in sub.
11. Zero both depth counters (Orion and Mechanical) at reference point.
12. Confirm all wellhead and BOP valves are in open position via physical check.

12.1. Prior opening the wellhead valve, pressure up above master valves to a pressure equal to the expected shut-in wellhead pressure.

12.2. Count and record wellhead valves turns while opening and record it the operation report for reference in future.

CV Opening Turns	LMV Opening Turns

12.3. Record initial SITHP and PCP in the Daily Operation Report (DOR).

12.4. Manipulate surface valve to the following position:

Valve	Position
Reel Manifold	OPEN
Flow Cross Return Valve (Cetco lines)	OPEN
Wing Valve	CLOSE

13. Prior to RIH, ensure to flag #1 CT at surface as indicator that CT Connector at stripper.

14. Start RIH BHA while pumping TIW at 0.3bpm until last encountered HUD depth at 143 m MDTHF with reference to previous Slickline HUD (or TRSV depth).

14.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer **Appendix III**.

14.2. Maximum coil speed running in hole is **30-50 ft/min.**

14.3. Closely observe weight indicator in control cabin while running in hole.

14.4. Conduct pull test minimum of every 300m (1,000ft) interval, use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.

14.5. Slow down coil speed to 10 ft/min before and after passing through completion accessories.

14.6. Observe return all the times. Flowback crew to monitor & record all return from time to time in Field Data Report.

14.7. Do not exceed operating safety limits **5,000 psi.**

14.8. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.

14.9. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.

15. Once BHA reached at 133 m MDTHF (10m above TRSV), stop CT and conduct pull test of 10m/30ft and record the pulling weight both static and dynamic in the DOR as per table below.

Depth	RIH weight, lbf	Static weight, lbf	Pick up weight, lbf

16. Start RIH & perform cleanout while pumping at 1.1 bpm starting at depth 133 m MDTHF until TRSV at depth 143 m MDTHF (Do not tag TRSV).

17. Once CT at 143 m MDTHF, perform jetting with TIW at max pump rate at 1.1 bpm for 30 minutes while exercise the flapper through control panel.

17.1. If no progress, perform high jetting at 1.1 bpm with 5 bbls of 15% HCl acid on top of TRSV Flapper.

If no progress, proceed to spot 5 bbls of 15% HCl acid on top of TRSV Flapper and soak for 2 hours. (Please refer chemical recipe for 15% HCl acid as per below table)

17.2. In the event of encounter waxy return at surface, spot 3 drums of WaxClean and soak for 3 hours (pickup to safe depth).

15% HCl				10	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	419	gptg	176	gals	Base Fluid
2	ACM CORR 400	4	gptg	2	gals	Acid Corrosion Inhibitor
3	MESB NE 200	4	gptg	2	gals	Non-Emulsifier
4	ACM Surf 210	3	gptg	1	gals	Surfactant
5	Ammonium Chloride	417	pptg	175	lbs	Clay Stabilizer
6	ACM Iron 300	25	pptg	11	lbs	Iron Sequestering
7	ACM Iron 200	15	gptg	6	gals	Iron Control
8	33% HCl	419	gptg	176	gals	Raw Acid
9	MESB MS 300	100	gptg	42	gals	Mutual Solvent

Mixing Instruction:
1. Fill up tank with Injection Water.
2. Add additives as per above sequence.
3. Agitate until mixture is homogenous.

18. Pick up CT to surface and waiting on soak time of 2 hours without nipple down the riser. 100 ft before CT reach to surface, ensure 1 pax crew standby near injector head to monitor the CT BHA inside the injector. Keep monitor flag #1 at surface.

19. Upon completion of acid soak, open return line & continue RIH to depth 133 m MDTHF (10m above TRSV) and unload all acid by establish return & neutralize at surface.

19.1. If unsuccessful, repeat step 16 for at least 2 times.

19.2. During circulation, if return is tested to be < pH 7, inject soda ash using chemical injection pump to the surface return line to neutralize the acid.

Neutralization Fluid				10	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	976	gptg	410	gal	Base fluid
2	Soda Ash	500	pptg	210	lbs	Neutralization fluid

Mixing Instruction:
1. Prepare injection water in the mixing tank.
2. Mix soda ash into tank and agitate until mixture is homogenous.

20. Upon completion of acid unload, perform circulate bottoms up with 20 bbls of TIW (4x volume from surface to TRSV) at 1.0 bpm.

21. POOH CT to surface while pumping at idle rate at 0.3 bpm.

22. 100 ft before CT reach to surface, ensure 1 pax crew standby near injector head to monitor the CT BHA inside the injector. Keep monitor flag #1 at surface.

23. Once at surface, handover to slickline for TCC.

CT RUN#1: SAND CLEANOUT FROM 1,573 M MDTHF UNTIL EOT AT 2,248 M MDTHF

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, personnel responsibilities, emergency well control drill, and safety precautions.

24. Make up 2-1/8" SpinCat Nozzle tool as per **BHA#2: 2-1/8" SpinCat Nozzle BHA** in **Appendix 1**.

    NOTE: Take the below measurement and record in the DOR.

25. Perform function test of the SpinCat Nozzle to determine the pumping parameter. Record the data in the table below, do not exceed 5,000psi.

Flow Rates (bpm)	N2 Rates (scfm)	Pressure (psi)	Remark
0.3			
0.5			
0.7			
0.8			
0.9			
1.0			
1.1			

26. Repeat step 6 till 12 in CT Contingency #1 prior making up BHA and open the well.
27. Start RIH BHA while pumping TIW at 0.3bpm until last encountered HUD depth at 1,573 m MDTHF with reference to previous Slickline HUD.
    - 27.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer **Appendix III**.
    - 27.2. Maximum coil speed running in hole is **30-50 ft/min.**
    - 27.3. Closely observe weight indicator in control cabin while running in hole.
    - 27.4. Conduct pull test minimum of every 300m (1,000ft) interval, use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.
    - 27.5. Slow down coil speed to 10 ft/min before and after passing through completion accessories.
    - 27.6. Observe return all the times. Flowback crew to monitor & record all return from time to time in Field Data Report.
    - 27.7. Do not exceed operating safety limits **5,000 psi.**
    - 27.8. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    - 27.9. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.
28. Once BHA reached at 1,563 m MDTHF (10m above previous HUD), stop CT and conduct pull test of 10m/30ft and record the pulling weight both static and dynamic in the DOR as per table below.

Depth	RIH weight, lbf	Static weight, lbf	Pick up weight, lbf

29. Establish return first by pumping at 1.1 bpm prior to penetrate by pumping 64 bbls of TIW (or consider 1x Completion Volume: 185 bbls if no return at surface).

Notes:

- If no return, please follow pumping parameter as per CIRCA: **0.9 bpm with 300 scfm (Minimum)**
- After establish constant return at surface, divert the flow into surge tank for 15 – 30 minutes, record the volume inside the surge tank to calculate losses rate into reservoir. Repeat this step every time change in choke size (due to several reason such as high and low THP).
- **Continuously record return volume during cleanout operation. (Record inside updated FDR)**
    - Check surface flowback back pressure. Must be less than WHP
    - Wait till system stabilizes
    - Check gas lift injection (Is it on? Injection Pressure > Wellbore Pressure?)
    - Manipulate choke size
- If still no return at surface, pick-up BHA by stages to establish return. (Proposed to depth where returns were previously obtained).
- If still unable to establish return, consult town. (Provide the details of THP, choke size and circulation pressure).
- After return establish, RIH to perform cleanout.
- At all times, monitor the return pattern, THP and debris sample at surface. (Take note if there any THP drop during penetration).
- **If no debris recover at surface while penetrating HUD with fluid return, stop penetration and circulate with Gel and CBU until debris recover at surface.**
- Pump 5 bbls gel to lift the suspected debris to surface.
- CBU at least 2x Annulus volume at that depth.
- After confirm there's no longer debris at that depth, proceed penetration.
- In the event unable to penetrate due to hard solid, slowly increase jetting rate until maximum allowable during penetration (ensure the return always establish at surface), after complete 1 cycle penetration, follow rate suggest by CIRCA to lift up the debris.

30. Continue RIH at 10 ft/min while pumping Nitrified TIW (0.9 bpm & 300 scf/min) starting at depth 1,573 m MDTHF until 2,248 m MDTHF (EOT).

Note: Every 30m/100ft penetration, sweep with 5 bbls of Gel & wiper trip 10m above previous HUD before continue penetrate in tubing section.

No.	Stage	Fluid	Liquid Rate	Total Liquid	N2 Rate (if require)	CT Speed	Duration	Depth	Remarks
			BPM	BBL	SCF/M	ft/min	Minute	m	
1	CT at 10m above HUD	TIW	1.0	0.0	300	0	0	10m above HUD (1,563 m MDTHF)	Establish return on surface
2	RIH to HUD and Penetrate HUD/Fill	TIW	1.0	10.0	300	10	30	HUD + 30m	Monitor return & CT weight on surface
3	Circulate	D801 Gel	1.0	5.0	300	0	5	Stationary CT	Provide suspension to the fill and lift to surface
Wiper Trip 10m above previous HUD									
4	RIH to last HUD and Penetrate HUD/Fill	TIW	1.0	10.0	300	10	10	HUD + 30m	Monitor return & CT weight on surface
5	Circulate	D801 Gel	1.0	5.0	300	0	5	Stationary CT	Provide suspension to

									the fill and lift to surface
Wiper Trip 10m above previous HUD and repeat step 1-5 until EOT at 2,248 m MDTHF									
6	Hole Cleaning (Circulate)	D801 Gel	1.0	40	300	0	40	Stationary CT @ EOT at 2,248 m MDTHF	Hole cleaning stage. 1.0x CT/Tubing Annulus Volume
7	Bottoms Up (Circulate)	TIW	1.0	560	300	0	560	Stationary CT @ EOT at 2,248m MDTHF	Hole Cleaning stage. As per Circa Simulation
Once completed CBU and clear return is established, Flag #1 CT at surface at 2,248 m MDTHF (EOT)									
Pick up CT to 2,243 m MDTHF & flag #2 CT at surface at 2,243 m MDTHF ('D' Nogo Nipple)									
Wiper trip to 1,150m MDTHF & make 2 passes across depth 2,230 m MDTHF									
8	POOH	TIW	0.3	72	300	30	240	To Surface	Monitor return on surface

31. If CT encountered hard obstruction, proceed to pick up CT 10m above the obstruction and circulate at least 2x bottom up until clear return is observe on surface before proceed with the following steps.

31.1. RIH and slack off CT not exceeding 500 lbf on top of the obstruction and attempt to jet on the obstruction. If no success mix **10 bbls of 15% HCl acid and Neutralization Fluid** as per the following recipe:

15% HCl (Main Treatment)				**10**	***BBL***	***Description***
Seq.	***Product***	***Concentration***		***Volume***		
1	Injection Water	419	gptg	176	gals	Base Fluid
2	ACM CORR 400	4	gptg	2	gals	Acid Corrosion Inhibitor
3	MESB NE 200	4	gptg	2	gals	Non-Emulsifier
4	ACM Surf 210	3	gptg	1	gals	Surfactant
5	Ammonium Chloride	417	pptg	175	lbs	Clay Stabilizer
6	ACM Iron 300	25	pptg	11	lbs	Iron Sequestering
7	ACM Iron 200	15	gptg	6	gals	Iron Control
8	33% HCl	419	gptg	176	gals	Raw Acid
9	MESB MS 300	100	gptg	42	gals	Mutual Solvent

Mixing Instruction:
1. Fill up tank with fresh water.
2. Add additives as per above sequence.
3. Agitate until mixture is homogenous.

Neutralization Fluid				**10**	**BBL**	**Description**
Seq.	**Product**	**Concentration**		**Volume**		
1	Injection Water	976	Gptg	410	gal	Base fluid
2	Soda Ash	500	pptg	210	lbs	Neutralization fluid

Mixing Instruction:
1. Prepare injection water in the mixing tank.
2. Mix soda ash into tank and agitate until mixture is homogenous.

31.2. Proceed to jet 5 bbls of 15% HCl on top of the obstruction (HUD) while attempt to pass through the obstruction.

31.3. If no success during jetting HCl acid, proceed to spot another 5 bbls of 15% HCl on top of obstruction (HUD) and pick up CT at least **550m** above the obstruction depth to soak the acid for 2 hours. After completed soaking, proceed to RIH to pass through the obstruction while pumping nitrified TIW. If unable to penetrate consult town for further instruction.

31.4. In the event of encounter waxy return at surface, spot 3 drums of WaxClean and soak for 3 hours (pickup to safe depth)

31.5. During circulation, if acid return observes on surface return line, inject soda ash using chemical injection pump on the surface return line to neutralize the acid.

32. Once CT reach 2,248 m MDTHF (EOT), circulate 40 bbls of Gel and perform bottoms up with Nitrified TIW (0.9 bpm & 300 scf/min) for 10 hours at depth 2,248 m MDTHF as per CIRCA Simulation. Flag #1 CT at surface at depth 2,248 m MDTHF (EOT).

Note: Perform pull test of CT at depth for every 30 minutes. Always monitor weight parameter.

Flag Number	*Colour*
Flag#1	

33. Pick up CT to 2,243 m MDTHF ('D' Nogo Nipple) & flag #2 CT at surface.

Flag Number	*Colour*
Flag#2	

34. Wiper trip to depth to 1,150 m MDTHF while pumping Nitrified TIW (0.9 bpm & 300 scf/min) at 10 ft/min.

34.1. Make 2 passes across depth 2,230 m MDTHF (Widepak Plug Setting Depth). Perform jet clean Widepak Plug Setting Depth 10 m above & 10 m below at high rate.

35. POOH CT to surface while pumping at idle rate at 0.3 bpm.

36. Once at surface, handover to slickline for TCC.

CT RUN#2: DEPTH CORRELATION & DRIFT RUN WITH 2.73" FLUTED CENTRALIZER

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, personnel responsibilities, emergency well control drill, and safety precautions.

37. In the event, slickline is unable to reach TD due to high deviation, CTU will enter this well and execute CT Run#2.
38. Make up 2-1/8" DownJet Nozzle c/w 2.73" FC tool as per **BHA#3: 2-1/8" DownJet Nozzle c/w 2.73" Fluted Centralizer BHA** in **Appendix 1**.
    I. Take each BHA measurement and record in the DOR
    II. Record length of BHA from CT Connector to lower part of Fluted Centralizer
39. Perform function test of the DownJet Nozzle to determine the pumping parameter and pressure of the tool. Record the data in the table below, do not exceed 5,000psi.

Flow rates (bpm)	Pressure (psi)	Remark
0.3		
0.5		
0.6		
0.7		
0.8		
0.9		
1.0		
1.1		
1.2		
1.3		
1.4		

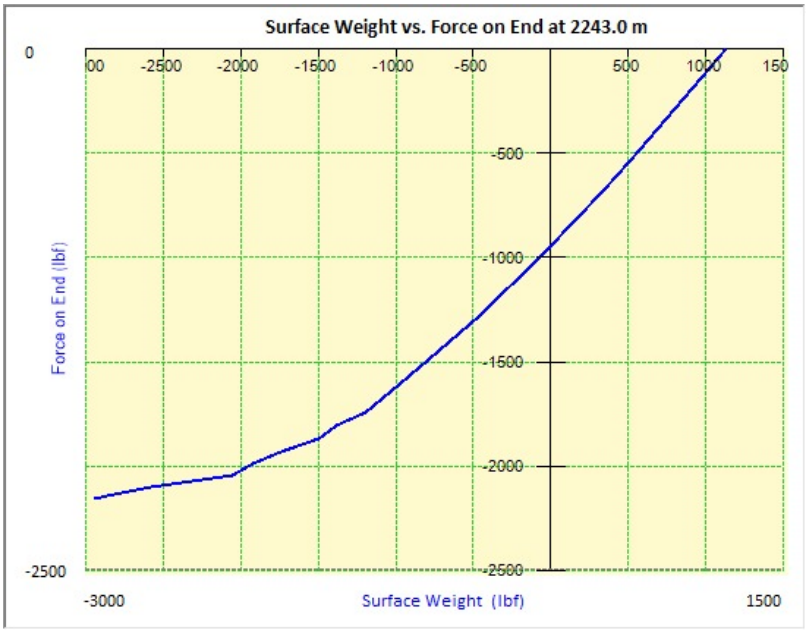
40. Repeat step 6 till 12 in CT Contingency #1 prior making up BHA and open the well.
41. Start RIH BHA while pumping TIW at idle rate until 2,233 m MDTHF (10m above 'D' Nogo Nipple).
    41.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer **Appendix III**.
    41.2. Maximum coil speed running in hole is **30-50 ft/min.**
    41.3. Closely observe weight indicator in control cabin while running in hole.
    41.4. Conduct **pull test minimum of every 500 ft interval**, use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.
    41.5. Slow down coil speed to 10 ft/min before and after passing through completion accessories.
    41.6. Observe return all the times. Flowback crew to monitor & record all return from time to time in Field Data Report.
    41.7. Do not exceed operating safety limits **5,000 psi.**
    41.8. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    41.9. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.

42. Once BHA reached at 2,233 m MDTHF (10m above 'D' Nogo Nipple), stop CT and conduct pull test of 10m/30ft and record the pulling weight both static and dynamic in the DOR as per table below.

Depth	RIH weight, lbf	Static weight, lbf	Pick up weight, lbf

43. Continue RIH slowly until 2,243 m MDTHF ('D' Nogo Nipple) based on reference of previous flag#2 in CT Run#1 (flag#2) until a loss weight is observed. Do not slack off more -1,000 lbf at downhole (downhole force).

    43.1. Please refer below set down force graph for reference:



    43.2. Once confirmed, flag the CT on surface, as Flag#3 & reset depth counter & Orion depth to 2,243 m MDTHF as per well schematic.

Flag Number	*Colour*
Flag#3 ('D' Nogo Nipple)	

44. Pick up CT to depth 2,230 m MDTHF (Widepak Plug Setting Depth). Once confirmed, flag the CT on surface, as Flag#4. This will be setting depth for Widepak Plug.

Flag Number	*Colour*
Flag#4 (Widepak Plug)	

45. POOH CT to surface & prepare for next run to set Widepak Plug at 2,230 m MDTHF.

CT RUN#3: SET WIDEPAK PLUG AT 2,230 M MDTHF

Conduct safety meeting with all personnel on location detailing the program, pressure limitations, personnel responsibilities, emergency well control drill, and safety precautions.

46. Make up Widepak Plug Setting tool as per **BHA#4: Widepak Plug Setting Tool BHA** in **Appendix 1**.
    - I. Ensure that burst disk at Motor Head Assembly (MHA) is changed to 6,000 psi pressure rating. Record the burst disk rating in BHA checklist, witnessed and verify by WSS.
    - II. Ensure 1/2" ball has been drifted through MHA, witnessed by WSS to confirm that it can pass through smoothly to the required ball seat in setting tool for Widepak Plug
    - III. Measure length of BHA & length from CT Connector to Packer Mid Element (COE) in ft.
    - IV. Ensure all BHA is properly torque according to Weatherford procedure.
    - V. Ensure quick test sub is in placed.
    - VI. Nipple up riser, pressure test quick test sub, pick up CT and tag the stripper and manipulate surface valve to the following position:

Valve	Position
Reel Manifold	OPEN
Flow Cross Return Valve (Cetco lines)	OPEN
Wing Valve	CLOSE

47. Start RIH to **2,200 m MDTHF (30 m above setting depth for Widepak Plug) while pumping break circulation at 0.3 bpm during pull test every 1,000 ft**.
    - 47.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix II.
    - 47.2. Ensure Weatherford Tool Specialist is available in Control Cabin at all time during operation.
    - 47.3. Conduct pull test as per for every 300m (1,000ft), use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.
    - 47.4. Maximum coil speed running in hole is **30-40 ft/min.**
    - 47.5. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
    - 47.6. Closely observe weight indicator in control cabin while running in hole.
    - 47.7. Observe return all the times.
    - 47.8. Do not exceed operating safety limits **5,000 psi.**
    - 47.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    - 47.10. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the Coiled Tubing at specified speed.
48. Once CT reach at **2,200 m MDTHF (30 m above setting depth)**, stop coil and conduct pull test of 10m/30ft without pumping and record the pulling weight both static and dynamic (IMPORTANT).

Depth, ft	*RIH weight, lbf*	*Static weight, lbf*	*Pick up weight, lbf*

49. Continue RIH slowly at 10ft/min to **2,240 m MDTHF (10m below setting depth).** 3m above previous Flag #3 in previous CT Run.
50. Pick up & tension CT to **2,230 m MDTHF (Widepak Plug Setting Depth) with reference of previous Flag#3**. Once get approval from town on the setting depth, perform the following step to set the Widepak Plug:

50.1. Record the coiled tubing pressure and close plug valve in the reel.

50.2. Bleed off the pressure of the surface line and reel manifold.

50.3. Ensure ball launcher is as close to vertical position as possible when launching.

51. At depth **2,230 m MDTHF setting depth**, launch ½" ball to set Widepak Plug. Follow instruction from Weatherford Tool Specialist.

51.1. Pump TIW at 1 bpm to chase the ball over gooseneck.

51.2. Once the ball has pass through the gooseneck, shutdown the pump and allow the ball to gravitate to it seat (approximately 30 minutes). In horizontal wells, the ball will have to be pumped down to the seat. The ball should be pumped to seat at minimum rate at 0.3 bpm with careful monitoring of the pump pressure.

51.3. When the ball bearing is fully seated, a pressure build up will be observed.

51.3.1. Slowly increase pressure to 1,500 psi by increment of 500 psi.

51.3.2. Apply set down weight 1,000 lbf and continue to pressure up to 3,500 psi by increment 500 psi to blow HST seat.

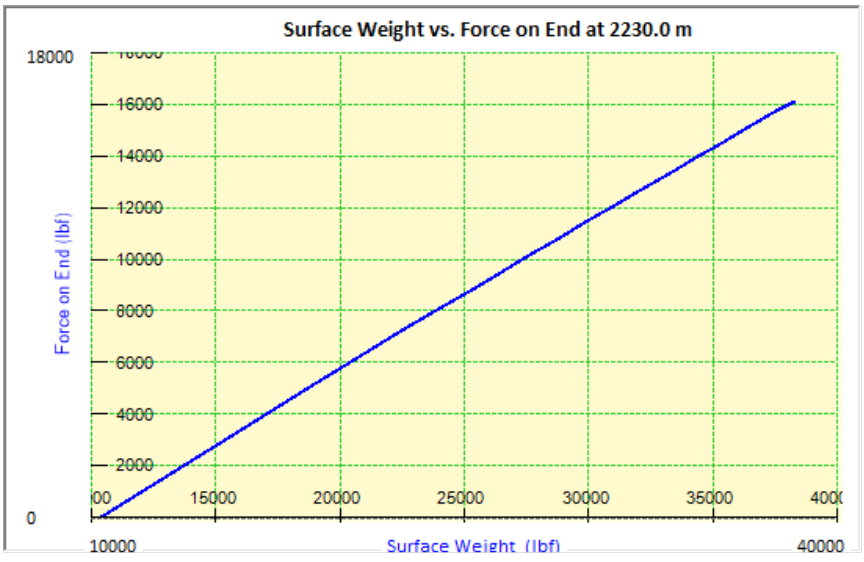
Note: Pressure drop will indicate the Plug is fully set

51.4. Once the plug is set, apply set down weight 2,000 lbf to confirm plug is fully set.

52. Pick up CT slowly and once confirmed free, continue POOH CT to **2,200 m MDTHF (30m above Plug)** (over-pull of 2,000 lbf at the tool over normal pick-up weight) to ensure plug is disconnected from the hydraulic setting tool. Monitor the pressure as pressure will drop when plug is disconnected from the setting tool.

52.1. Shut down the pump and wait for 20 minutes for fluid across the plug to be stabilized.

52.2. Please refer below pick up force graph for reference:



52.3. Record the pulling weight both static and dynamic.

Depth	RIH weight, lbf	Static weight, lbf	Pick up weight, lbf

53. Record all parameters (SITHP and CHP). For positive pressure test, make sure the valves are in following position:

Valve	Position
Lower Master Valve	OPEN
Swab Valve	OPEN
Kill Line	OPEN
Wing Valve	CLOSE

54. Pressure test the plug by pumping TIW thru CT annulus, apply 500 psi and monitor the pressure for 30 minutes.

    54.1. Record all essential parameter (Pumping pressure, Pumping Rate, SITHP and CHP)

Time	Pump Rate (bpm)	Pumping Pressure (psi)	THP (psi)	CHP (psi)

    54.2. If integrity test is satisfactory, proceed with next step.

    54.3. If integrity test failed, pressure drop is more than 10% (Registered pressure = below 450 psi), consult Engineer in Charge (EIC).

55. Upon obtain positive result, bleed off the pressure and shut in the well. Proceed with negative pressure test. Monitor THP for 30 minutes.

    55.1. Record all essential parameter (Pumping pressure, Pumping Rate, SITHP and CHP)

Time	Pump Rate (bpm)	Pumping Pressure (psi)	THP (psi)	CHP (psi)

56. Upon complete Plug Integrity Test, continue POOH CT to surface while pumping TIW at 0.3 bpm. Ensure continuous return on surface is observed.

    56.1. Maximum CT speed while POOH is 50 ft/min.

    56.2. Slow down CT speed to 10 ft/min before and after passing through completion accessories.

57. Once CT on surface, close well and bleed off pressure in coil and stack up.

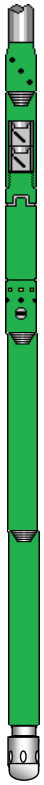
APPENDIX I – BHA SCHEMATIC

BHA#1: 1.5" CLEANOUT NOZZLE BHA (SLIM BHA)

DIMENSION BID

BHA DIAGRAM #1 - 1.5" Cleanout Nozzle BHA

Client	Petronas Carigali	Well	D-22
Field	Dulang D	Min Restriction	2.75"
Job Type	Sand Cleanout	BHP	
Job No.		BHT	228 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**Internal Dimple CT Connector**	1.5" CT	10 SA Pin		1.500	0.5	0.5
	MHA Disconnect drop ball 1/2" Shear pressure 6,876 psi Circulating drop ball 3/8" Shear pressure 2,512 psi Burst Disc 5000 psi	10 SA Box	10 SA Pin		1.500	2.3	2.8
	3 FT Straight Bar	10 SA Box	10 SA Pin		1.500	3.0	5.8
	3 FT Straight Bar	10 SA Box	10 SA Pin		1.500	3.0	8.80
	1.5" Cleanout Nozzle	10 SA Box			1.500	0.4	9.2

BHA LENGTH	9.20
MAXIMUM OD	1.50
MINIMUM ID	

Prepared by:	Muhd Ameerul Zaeem
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

Ensure to measure length and OD of each BHA tool before makeup.

BHA#2: 2-1/8" SPINCAT NOZZLE BHA

DIMENSION BID

BHA DIAGRAM #1 - 2-1/8" SpinCAT Nozzle BHA

Client	Petronas Carigali	Well	D-22
Field	Dulang D	Min Restriction	2.75"
Job Type	Sand Cleanout	BHP	
Job No.		BHT	228 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**External Dimple CT**	1.5" CT	1.5" AMMT PIN		2.125	0.6	0.6
	MHA Disconnect drop ball 3/4" Shear pressure 5,636 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5000 psi	1.5" AMMT BOX	1.5" AMMT PIN		2.125	2.5	3.1
	5 FT Straight Bar	1.5" AMMT BOX	1.5" AMMT PIN		2.125	5.0	8.1
	Downhole Filter 100 Micron Size	1.5" AMMT BOX	1.5" AMMT PIN		2.125	3.2	11.3
	2-1/8" SpinCAT Nozzle 5k psi rated Up to 390 F	1.5" AMMT BOX			2.125	1.0	12.3

BHA LENGTH	12.30
MAXIMUM OD	2.13
MINIMUM ID	

Prepared by:	Muhd Ameerul Zaeem
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

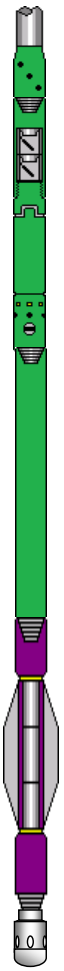
Ensure to measure length and OD of each BHA tool before makeup.

BHA#3: 2-1/8" DOWNJET NOZZLE C/W 2.73 FC BHA

DIMENSION BID

BHA DIAGRAM #3 - 2-1/8" DownJET Nozzle c/w 2.73" Fluted Centralizer BHA

Client	Petronas Carigali	Well	D-22
Field	Dulang D	Min Restriction	2.75"
Job Type	Sand Cleanout	BHP	
Job No.		BHT	228 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**External Dimple CT**	1.5" CT	1.5" AMMT PIN		2.125	0.6	0.6
	MHA Disconnect drop ball 3/4" Shear pressure 5,636 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5000 psi	1.5" AMMT BOX	1.5" AMMT PIN		2.125	2.5	3.1
	5 FT Straight Bar	1.5" AMMT BOX	1.5" AMMT PIN		2.125	5.0	8.1
	2.73" Fluted Centralizer	1.5" AMMT BOX	1.5" AMMT PIN		2.730	2.30	10.4
	2-1/8" DownJet Nozzle	1.5" AMMT BOX			2.125	0.8	11.2

BHA LENGTH	11.20
MAXIMUM OD	2.73
MINIMUM ID	

Prepared by:	Muhd Ameerul Zaeem
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

Ensure to measure length and OD of each BHA tool before makeup.

BHA#4: 2.72” WIDEPAK PACKER BHA

DIMENSION BID

BHA DIAGRAM #4 - 2.72" Widepak Packer

Client	Petronas Carigali
Field	Dulang D
Job Type	Sand Cleanout
Job No.	

Well	D-22
Min Restriction	2.75"
BHP	
BHT	228 F

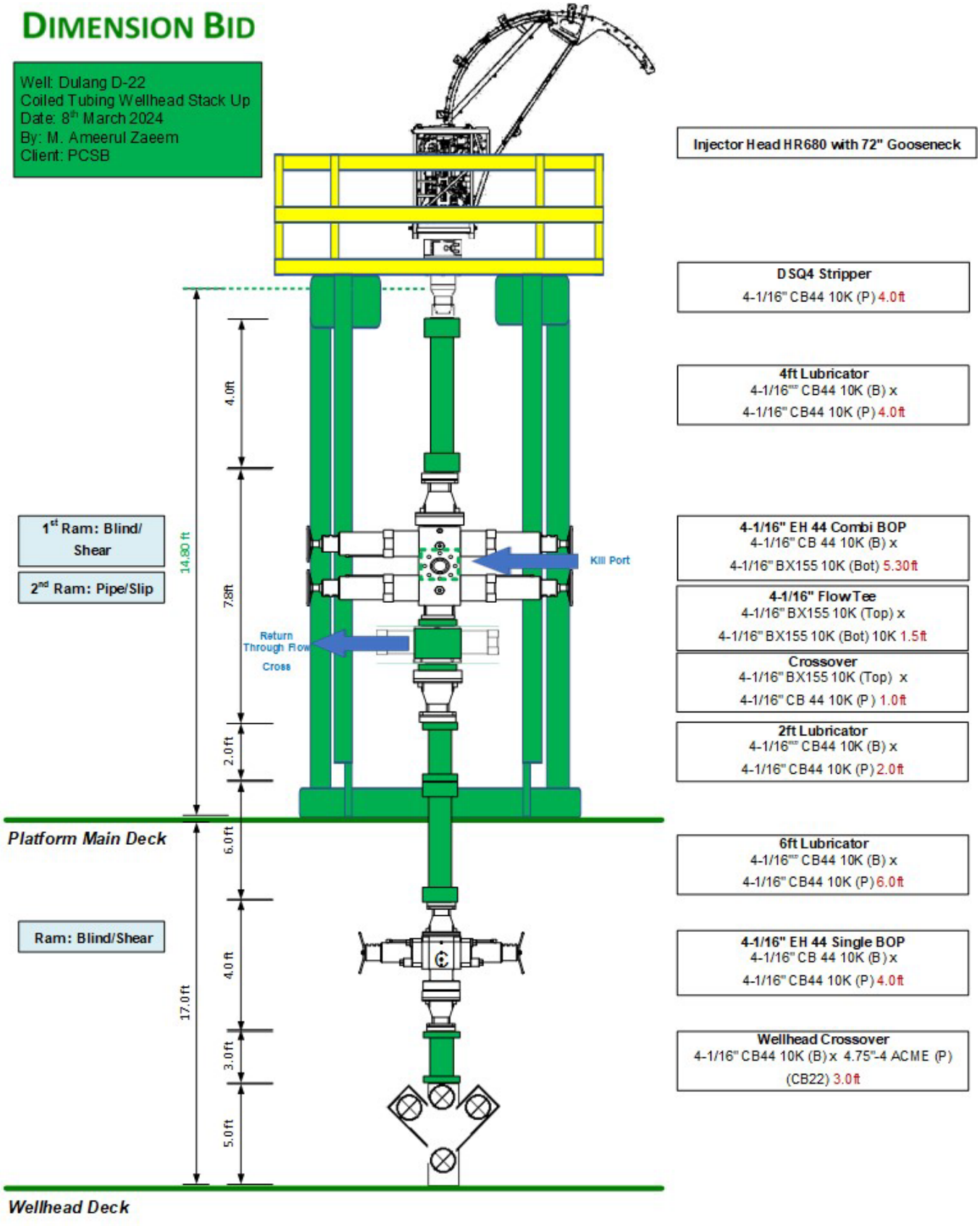
BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**External Dimple Connector**	1.5" CT	1.5" AMMT PIN		2.125	0.4	0.4
	MHA Disconnect drop ball 3/4" Circulating drop ball 5/8" Burst Disc 6000 psi	1.5" AMMT BOX	1.5" AMMT PIN		2.125	2.3	2.7
	Crossover	1.5" AMMT BOX	1.25: WTS-8 PIN		2.125	0.50	3.20
	Hydraulic Setting Tool 0.5" Ball Size to set plug Phenolic Type Ball	1.25: WTS-8 BOX	Baker #5		2.125	5.4	8.6
	Wireline Adapter Kit	Baker #5	2.3" Special VLH		2.700	0.65	9.25
	Widepak SLE Packer c/w Equalizing Valve Require setting force: 22,225 lb Release force: 3,700 lb	2.3" Special VLH	1.9" EUE Pin		2.720	4.00	13.25

BHA LENGTH	13.25
MAXIMUM OD	2.72
MINIMUM ID	

Prepared by:	Muhd Ameerul Zaeem
Review by:	
Revision:	
Date:	

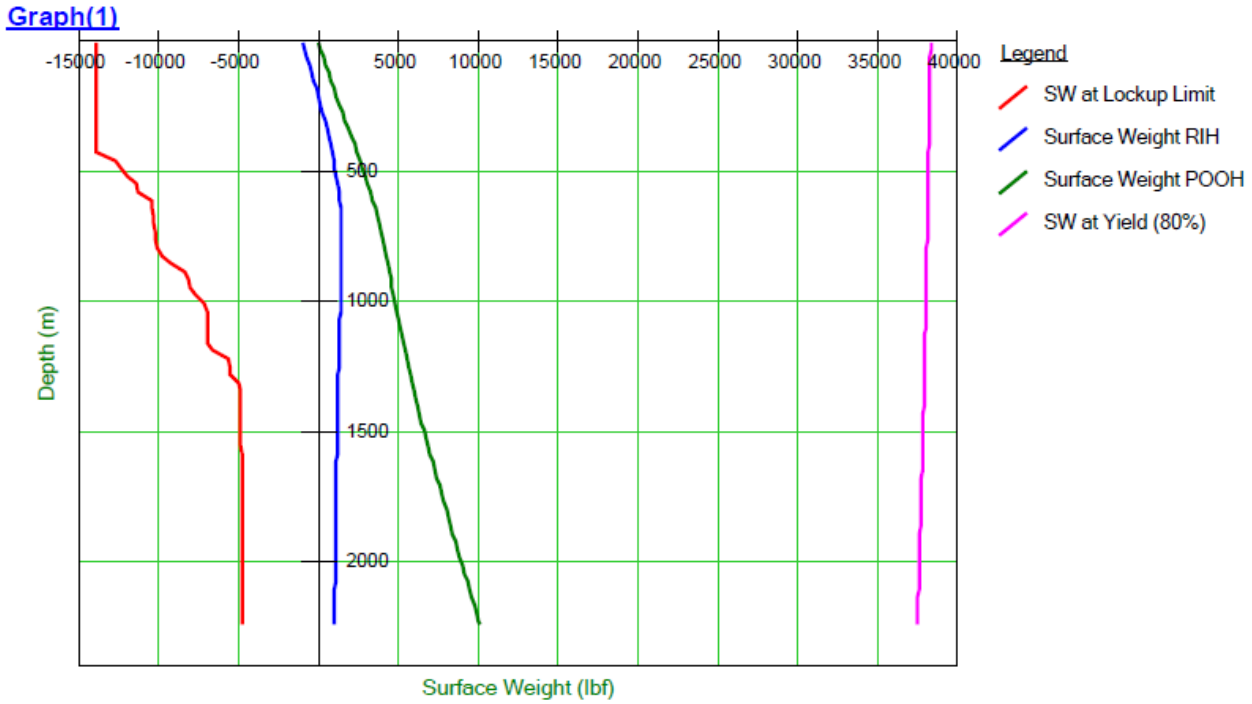
ADDITIONAL INFORMATION:
Ensure to measure length and OD of each BHA tool before makeup.

APPENDIX II – CT STACK UP

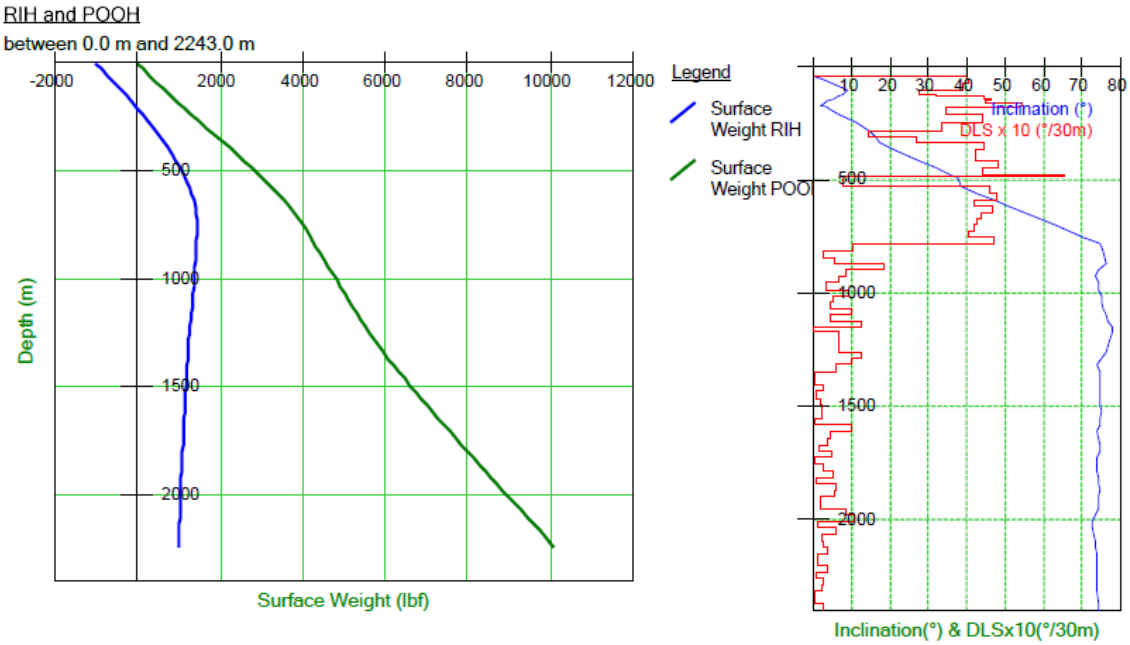


APPENDIX III – ORPHEUS SIMULATIONS

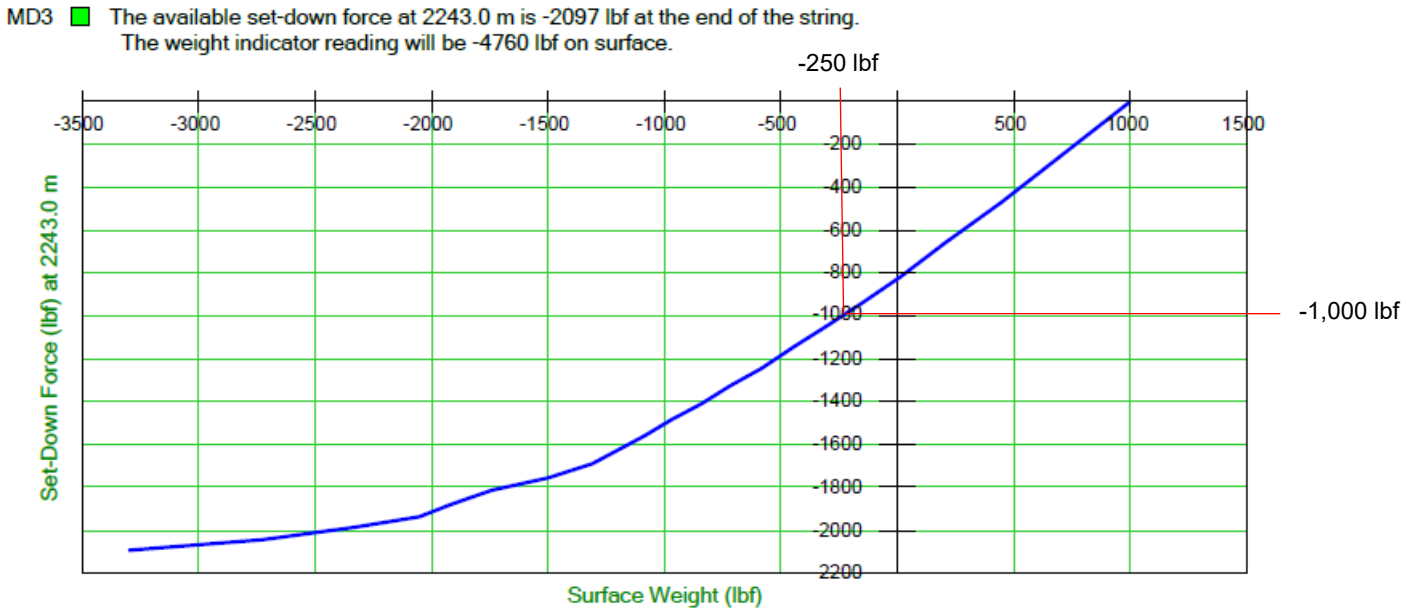
TUBING FORCE ANALYSIS AT 2,243 M MDTHF



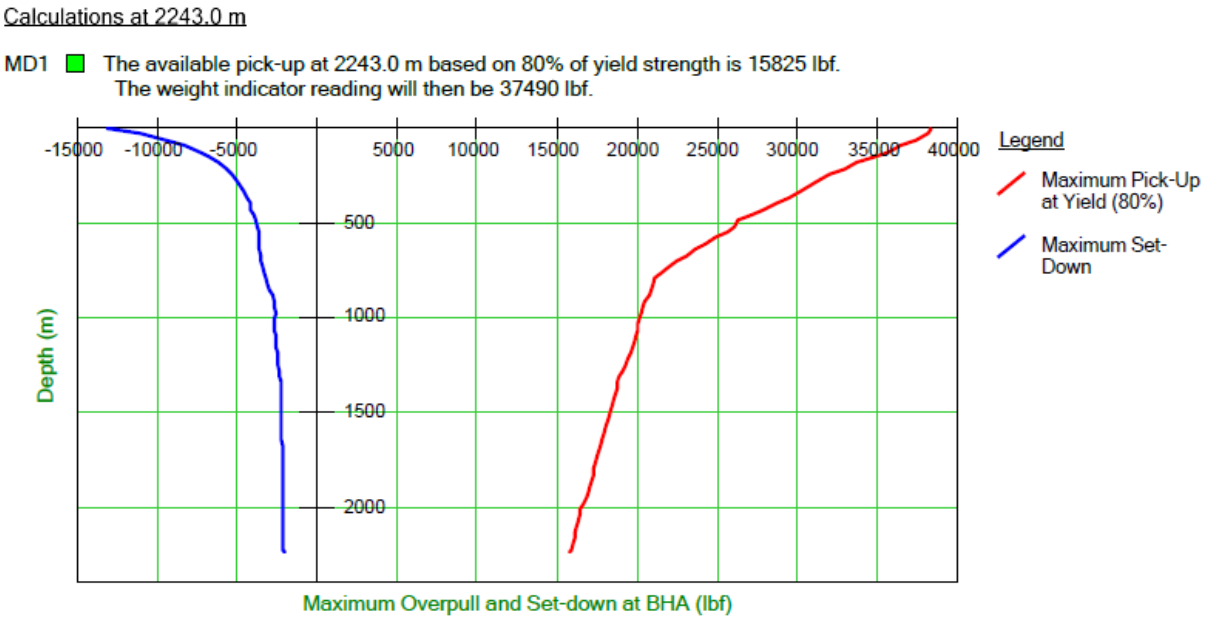
RIH & POOH WEIGHT



MAXIMUM STRING SET DOWN LIMIT

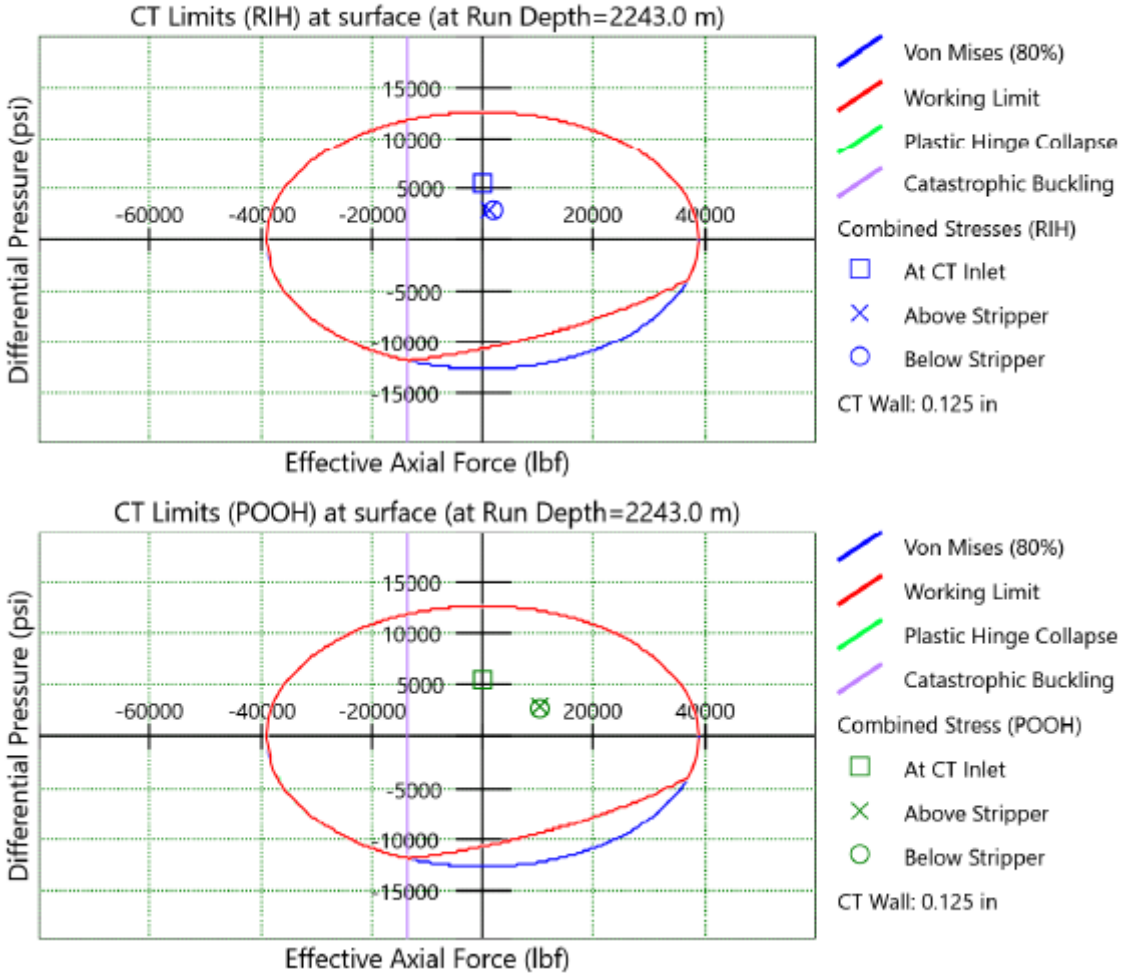


MAXIMUM STRING PICK UP LIMIT



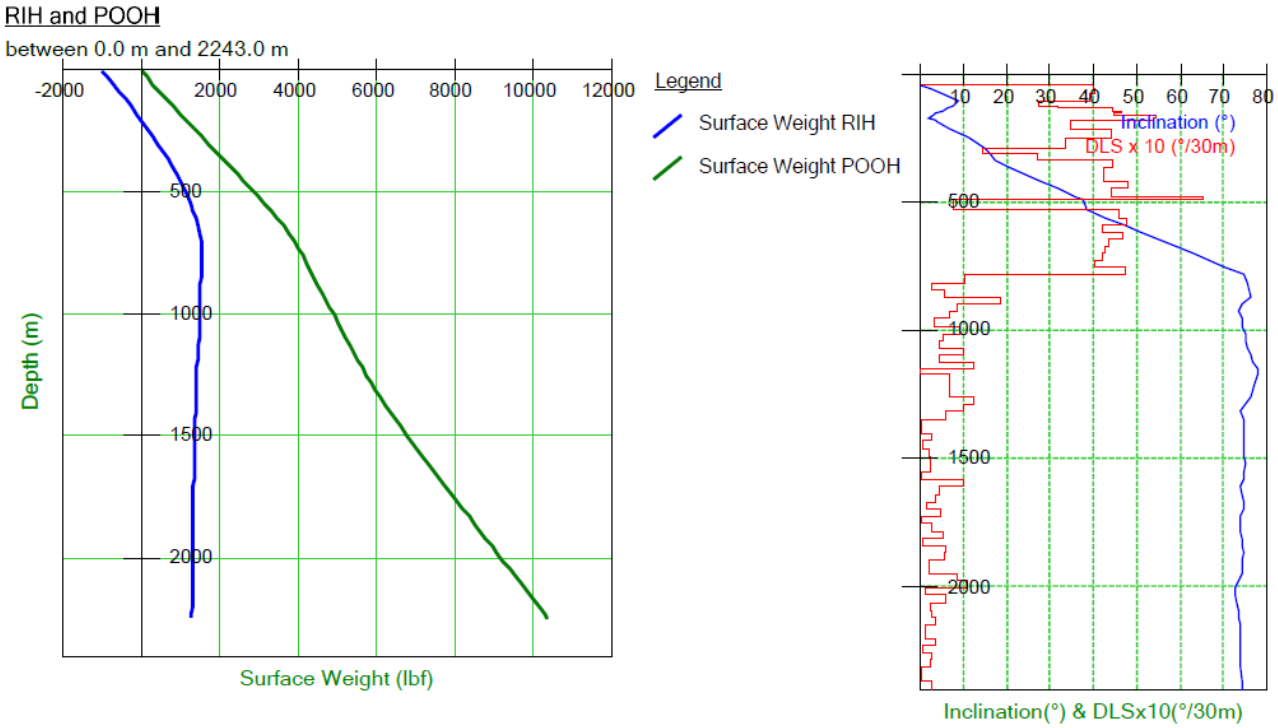
STRING LIMIT

CT Limits

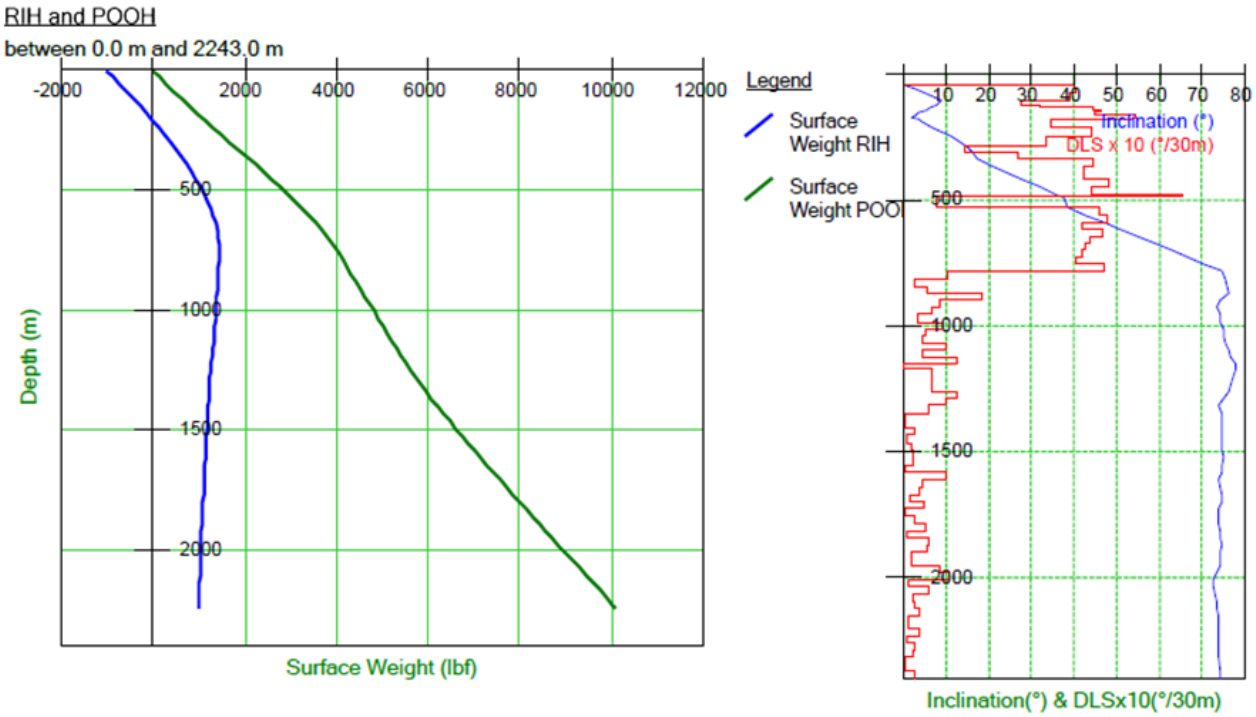


SENSITIVY ANALYSIS TFA

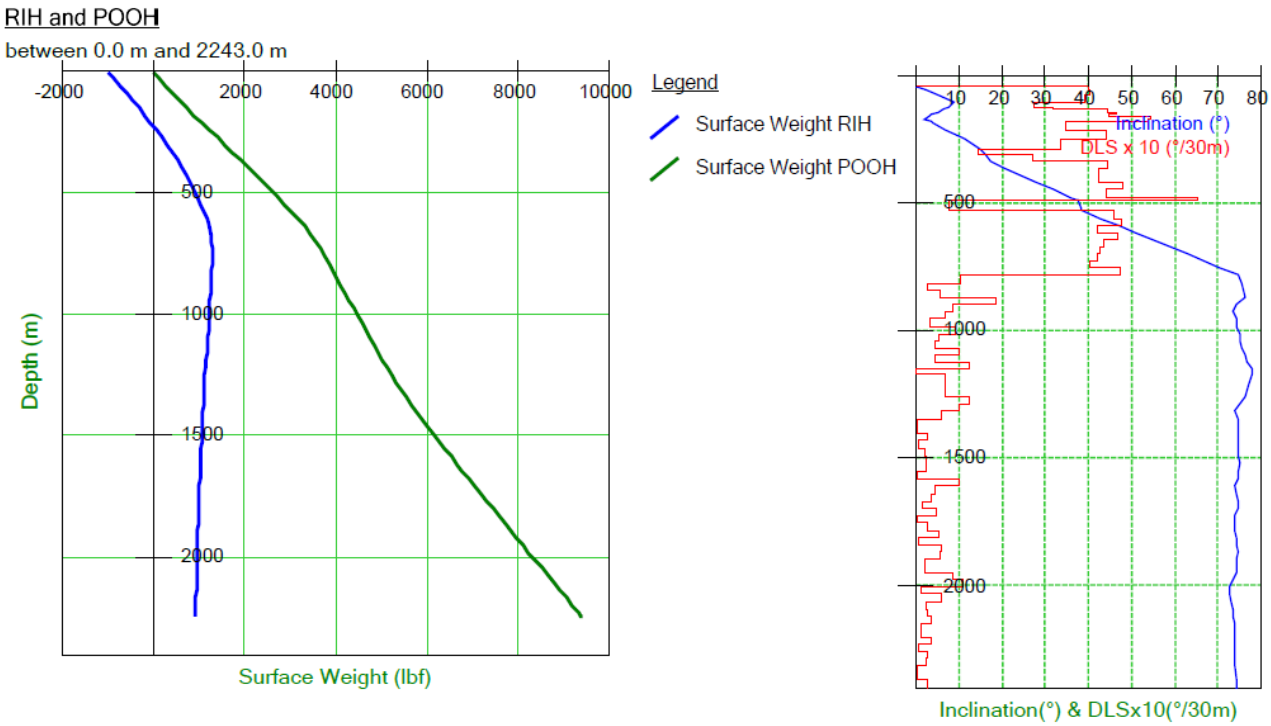
Idle Rate (0.3 bpm)



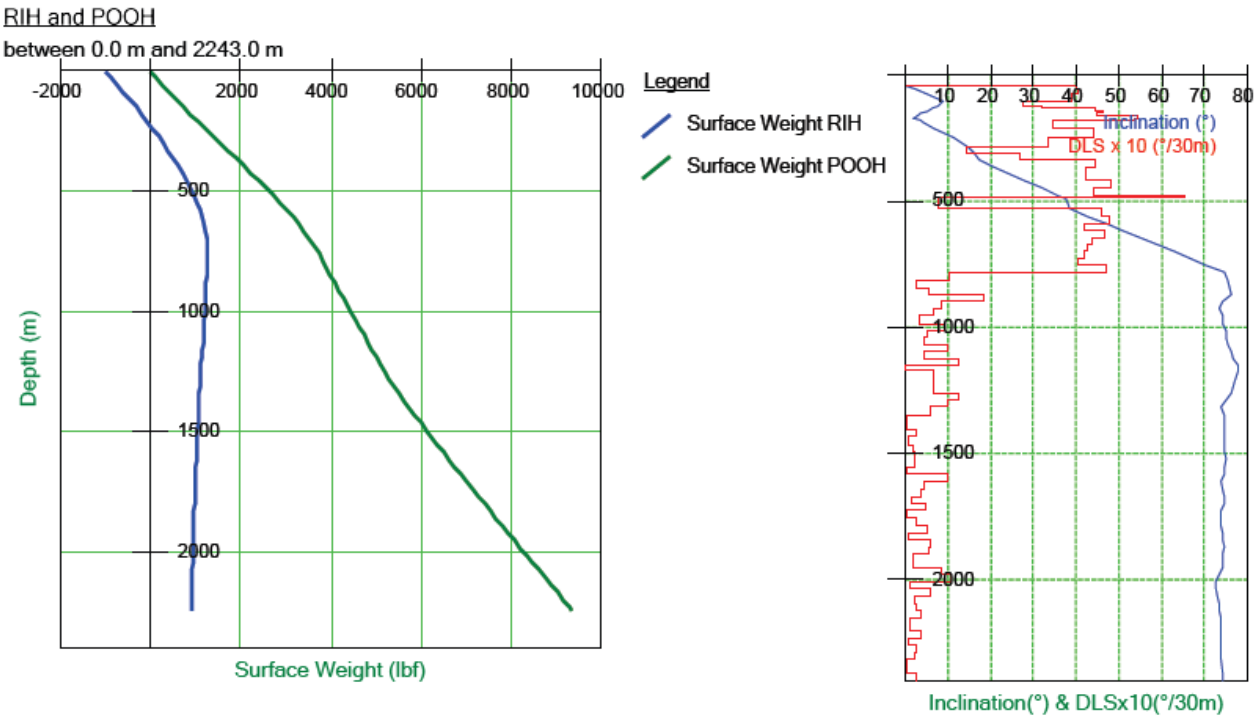
High Rate (1.1 bpm)



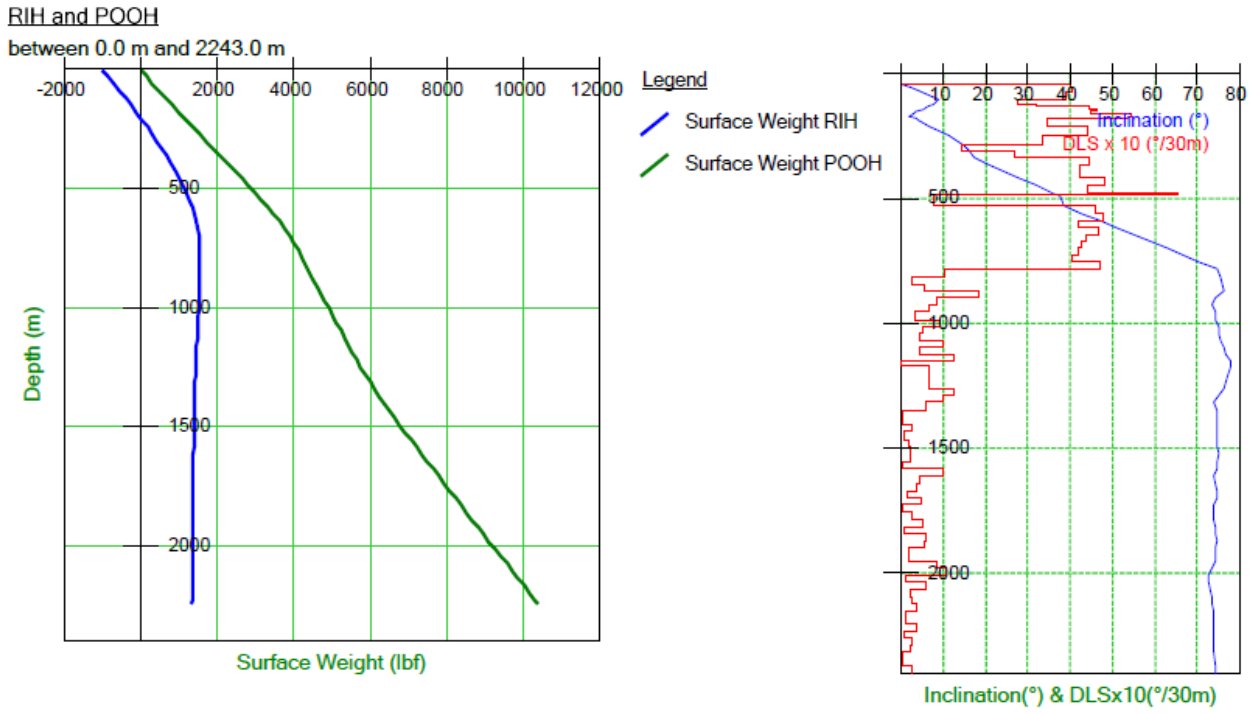
Nitrified (0.9 bpm 300 scf)



Nitrified (0.9 bpm 400 scf)

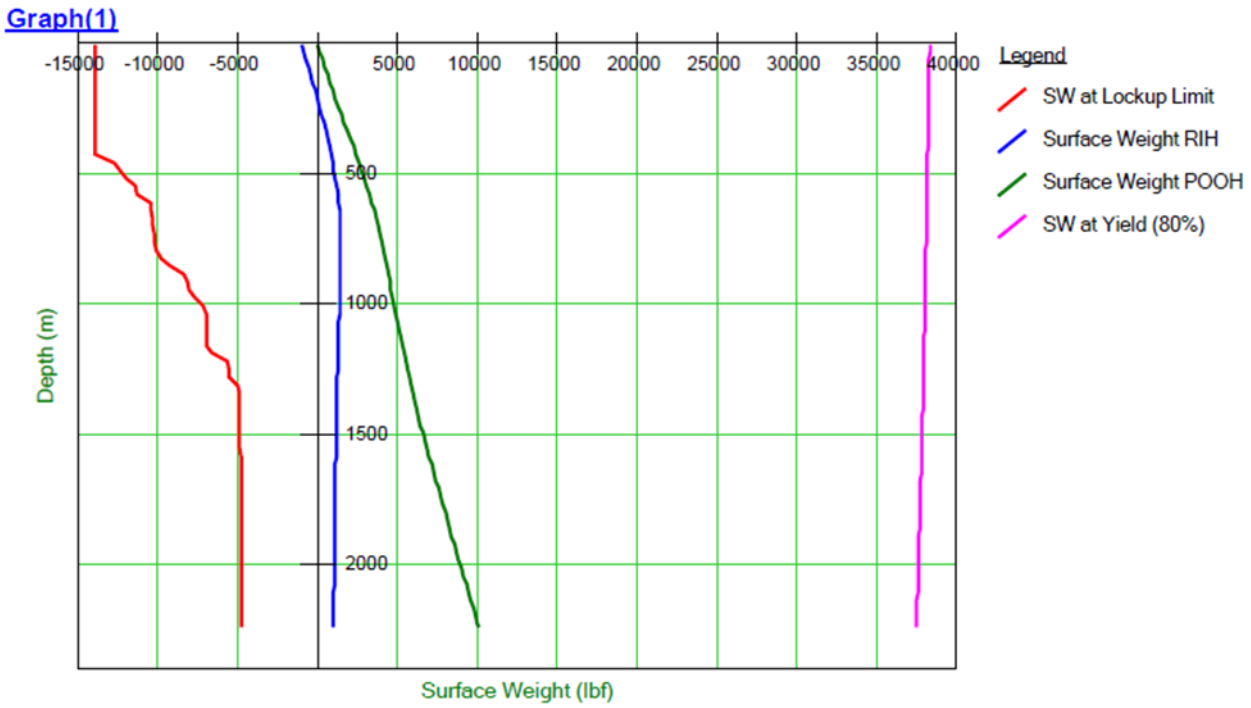


Without pumping (0 bpm 0 scf)

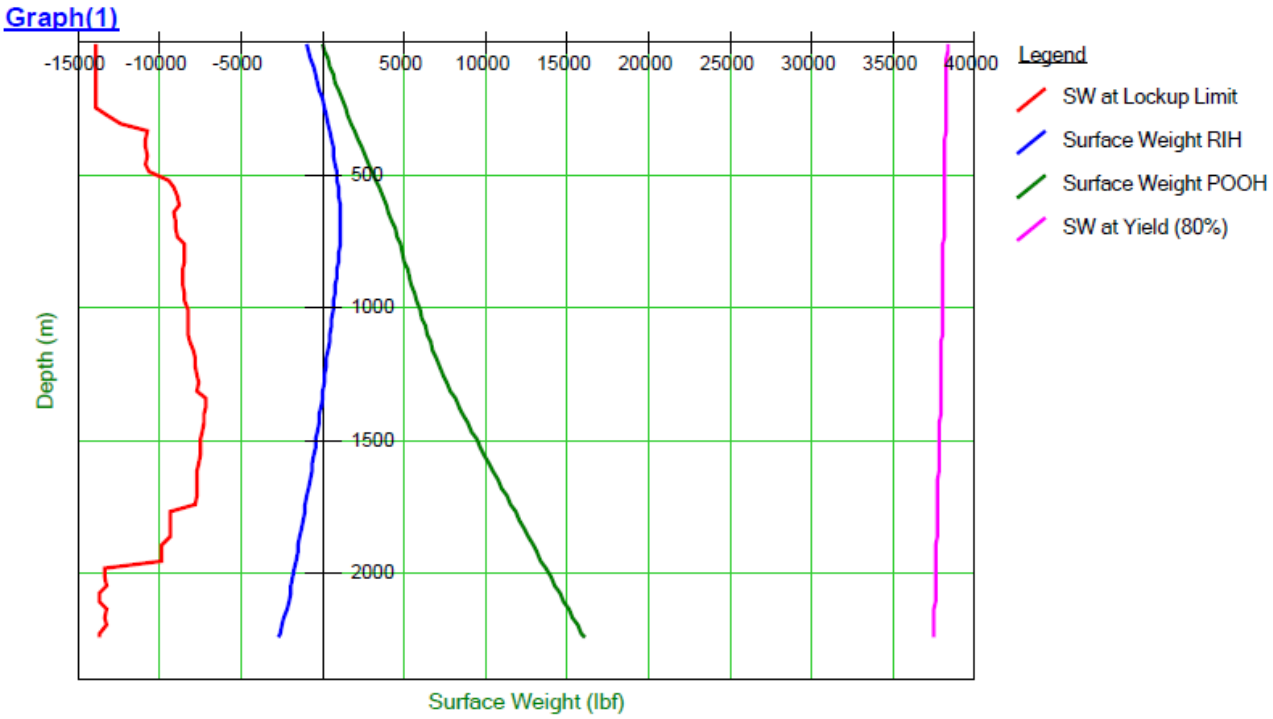


SENSITIVY ANALYSIS FRICTION FACTOR

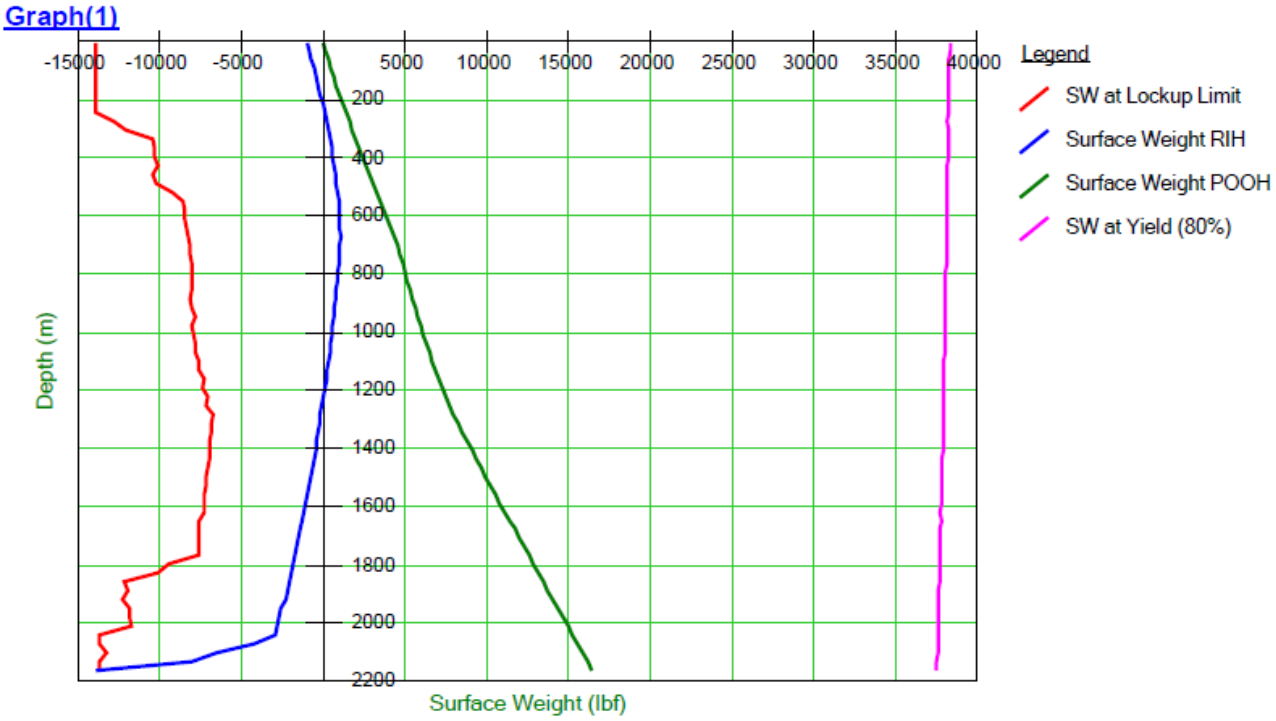
Friction Factor 0.3 (Default Value)



Friction Factor 0.5



Friction Factor 0.7 (Lock up detected at depth 2,164m MDTHF)



SUMMARY OF TUBING FORCE ANALYSIS AT DEPTH 143 M MDTHF (TRSV)

Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
0 BPM	-6,905	-13,961	35,176	38,290
0.3 BPM	-6,903	-13,961	35,176	38,289
1.1 BPM	-6,879	-13,912	35,137	38,234
Nitrified (0.9 BPM & 300 SCF/M)	-6,817	-13,762	34,648	37,662
Nitrified (0.9 BPM & 400 SCF/M)	-6,797	-13,686	34,346	37,335

SUMMARY OF TUBING FORCE ANALYSIS AT DEPTH 2,248 M MDTHF (EOT)

Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
0 BPM	-2,243	-4,243	16,104	38,303
0.3 BPM	-2,223	-4,282	16,116	38,304
1.1 BPM	-2,097	-4,760	15,825	37,490
Nitrified (0.9 BPM & 300 SCF/M)	-2,054	-4,623	16,045	37,296
Nitrified (0.9 BPM & 400 SCF/M)	-2,048	-4,623	15,942	37,062

APPENDIX IV – EMERGENCY PROCEDURE

EMERGENCY BOP OPERATIONS

In the event of an emergency arising and the well having to be secured, the following steps should be taken:

1. Stop CT movement, close the Slip and Pipe rams and slack off string weight to ensure slips are holding. If time permits, review all options with the client representative. (Ensure that rams with guides are activated first to avoid damaging the CT).

   Note: The decision to proceed past the above step should normally be made after consultation with the client representative unless there is an immediate and serious danger to personnel and/or equipment and the client representative is not immediately available to be involved in the decision.

2. Stop pumping.
3. Close the upper Shear Seal rams to cut the CT.
4. Set up to circulate well to kill fluid through the CT remaining in the well.
5. Make arrangements necessary to fish the CT from the BOP.

   Note: When actuating any ram in the BOP system, the corresponding manual lock should be closed behind it to prevent accidental release in the event of total loss of hydraulic power. The force required to close the rams manually against pressure cannot be supplied by turning in the locks. Use of a pipe wrench, cheater bars or snipes will damage the internal workings of the ram actuators. Some form of hydraulic power is required to operate the actuators. This pressure can be supplied via a hand pump or a hydraulic pump from any other piece of equipment on location, including a fluid pumper.

Actuating the BOP System Hydraulic Controls

1. Remove locks on control panel
2. Move the control lever to the desired position.
3. Push the BOP activate button supplying pressure to the circuit.
4. Observe the pressure drop in the hydraulic circuit and subsequent pressuring back up to system pressure as ram opens or closes completely.
5. Observe the ram indicator pins to verify the operation of the ram.
6. Close in the manual locks if required. (Flag system to indicate position of rams.)

The connections below the CT BOP must be all flanged. Should one of these connections start leaking, the following steps should be taken in consultation with the client representative:

1. Call local alert and ensure all personnel are removed from the wellhead area.
2. Notify the client representative of the problem and determine the best method to make the area safe.
3. If the leak is minor, it may be possible to continue to pull the CT to surface. Assess the scenario and consider all the risks associated then proceed to pull the CT to surface. Once at surface, close available valves below the leak point.
4. If the leak is more severe, initiate a well kill through the well kill line and continue to pull the CT to surface.
5. If the leak is catastrophic, run the CT to HUD; pick up sufficient so that after the CT is cut at surface by CT BOP shear; the top of the CT falls below the X-mass Tree. Once the end of the CT is off bottom, proceed to cut the cut the CT with the shear RAM then close the available valves below the leak point. A well kill operation can be started through the kill line if requested by the client representative.

LEAK IN CT AT SURFACE

In the event of a leak in the CT occurring at surface, the following steps should be taken:

1. Call local alert and ensure all personnel are removed from the operational area. In particular make sure all personnel remain clear of the area between the Injector Head and the CT reel.
2. If the leak is small or a pinhole leak, POOH and position the leak on the lower part of the CT reel as soon as possible. Be careful when area of leak is bent onto the reel as failure may occur. Make arrangements to have a water hose present to wash away any fluid from the reel which may be hazardous. Make arrangements to start pumping water through the CT reel. Depressurize reel as much as conditions allow without exceeding collapse limitations of CT.
3. Notify client representative of problem and determine best method to make area safe. If leak is minor and water can be displaced to leak, continue to POOH and change reel.
4. If leak is considered to be too serious to displace to water and POOH, or serious and uncontrolled leakage of hydrocarbon or hazardous materials prevents this, (i.e. check valves not holding, lost BHA, parted CT) set the CT slips and pipe rams. Activate the upper Shear Seal rams on either the triple or quad BOP and manually lock in place.
5. Depressurize the CT reel and flush through the reel. If hydrocarbons are present in the reel, displace the reel with water and empty the contents to specified safe disposal area.

LEAK IN CT BELOW SURFACE

If a leak occurs in the CT below the Stuffing Box during down hole operations (usually indicated by a drop in pump pressure or loss of string weight), suspend CT operations and alert the client representative.

Note: If indications are that the BHA has been lost in hole then revert to section 0.

1. Once the client representative has been alerted, clear all personnel from the immediate area of the CT around the Injector Head and between the Injector Head and the CT reel.
2. Displace the CT to water and commence to POOH at not more than 20 ft per minute (5 meters/min). Ensure at all times that all personnel are clear of the immediate area as the possibility exists to pull the CT out of the Stuffing Box. Continue pumping water at a slow rate through the CT.
3. When the leak in the CT appears above the Stuffing Box, stop the injector and hold the leaking section of CT between the chains and the Stuffing Box.
4. Inspect leak. If leak is minor continue to POOH.
5. If leak is major, or CT is actually severed or well bore fluids are escaping through the CT, continue as per Section 09.2.

LEAK IN SURFACE PRESSURE CONTROL EQUIPMENT

Stuffing Box

1. **Stop** CT movement and close both sets of pipe rams to seal CT annulus. Set manual lock.
2. On semi-submersible operations this will be a set of pipe rams and pipe/slip rams.
3. Notify Client representative.
4. Ensure the injector is in neutral and that the brake is engaged.
5. Bleed off pressure above pipe rams
6. Set reel brake. On Semi-Submersible jobs the CT should be clamped at the level wind and CT run out of hole until enough slack between the injector and reel is obtained to cope with the heave from the rig, prior to setting reel brake.
7. Bleed off closing pressure on Stuffing Box. Open side doors and apply pressure to retract piston. Replace packer elements and then re-apply pressure to Stuffing Box. Close side doors.

   Note: 3" side door Stuffing Boxes first bleed off closing pressure. Remove hoses from pack and retract piston and connect to open and close on side door. Open door and replace packer element. Close door, bleed off pressure and connect to pack and retract piston.
8. Slowly open both equalizing valve on pipe rams and check that stripper is holding pressure.
9. If stripper is holding pressure, undo manual locks and open pipe rams or pipe slip rams. When using pipe/slip rams the depth that they were set on the CT must be recorded. Release reel brake and continue operations.

Surface Leaks Other Than Stuffing Box

1. If leak is minor and a relatively short length of CT is in the hole and the Shear Seal safety head is **below the leak:**
2. Call local alert and notify the client representative.
3. Clear all non-essential personnel away from the area
4. Continue POOH and monitor situation closely
5. Hook up kill line to BOP and pump water slowly down annulus.

Note: Avoid collapse situation

1. Close swab valve and Shear Seal once CT is in riser and repair leak
2. Perform reinstatement test on surface equipment after leak has been repaired
3. If CT is in the well to a considerable depth and leak is considered serious:
4. Call local alert and notify Client representative.
5. Ensure all non-essential personnel are removed from the area.
6. Ensure that CT is sufficiently off bottom so that when the Shear Seal safety head is activated the pipe will drop below the Xmas tree manual master valve. If the CT is stuck down hole, pull to 80% of operating limit before activating Shear Seal BOP, thus allowing the CT to drop below the Xmas tree manual master valve. If the CT is attached to a fish, packer etc pull to 80% of operating limit (if possible) or maximum weight possible before activating Shear Seal BOP, thus allowing the CT to drop below the Xmas tree manual master valve. **If at all possible**, the decision to cut the CT and activate the system will be taken by the Client representative in charge of the operation. This may not always be possible. If the situation is extremely dangerous and requires a fast decision, the Supervisor in charge will take this decision.

7. Close the Shear Seal rams in the safety head to cut the pipe and allow it to drop. (If the safety head has separate shear and blind rams, close the shear rams to cut the pipe, pull up the CT and close the blind rams).
8. Close the swab valve on the Xmas tree.
9. Close the master valve on the Xmas tree
10. Repair leak and pressure test riser.
11. Plan for fishing operations.

Rotating Joint Leak

Eliminate the potential for reel movement by securing the reel with turnbuckles and set reel brake. On Semi-Submersible jobs the CT should be clamped at the level wind and CT run out of hole until enough slack between the injector and reel is obtained to cope with the heave from the rig. Close the reel isolation valve inside the reel and repair or replace the rotating joint as required. Re-test and resume operations.

CT RUNS AWAY INTO WELL

If the inside chain tension system on the Injector Head should fail for any reason, and CT is pulled into the well under its own weight with no control, the procedure should be as per the following:

1. Call a local alert.
2. Attempt to speed the injector up to match the speed of the descending CT.
3. Increase inside chain tension to increase friction on CT.
4. Increase stripper pressure to exert more friction on CT.
5. If these actions fail to make any difference, reduce injector hydraulic pressure to zero.
6. In the event that there is insufficient CT on the reel to reach bottom close CT slips. This action may damage or break the CT. This is the preferred option to using the pipe rams as these will become damaged and a primary well control system will be lost.
7. If the CT is not too far off bottom it may be practical to let it fall to bottom then investigate the causes and repair. This can only be done if there is sufficient CT on the reel to reach bottom.

Note: CT may helix when hitting bottom making it difficult to pull into tail pipe.

8. Once CT has been controlled, examine Injector Head for damage including chains and POOH.
9. The CT run away may be caused by the injector becoming overloaded with the weight of the CT and fluid in the CT. This situation should not occur if proper pre job planning is done. Correct selection of Injector Head or ensuring CT is full of Nitrogen would prevent this situation from occurring.
10. If a runaway situation occurs, reduce the injector hydraulic pressure to zero. This may cause the safety brake in the motors to actuate and counter balance valves to close, stopping the injector.
11. Under certain circumstances if the runaway CT is at a speed above the critical speed, the back pressure created by the circulating hydraulic fluid may prevent the injector motor brakes from actuating. If this situation occurs, select the pull mode for the injector and increase system hydraulic pressure until the CT comes to a standstill.

CT IS PULLED OUT OF STUFFING BOX

This situation is most likely to occur when the CT is being pulled into the riser section. If the BHA is lost including the End Connector there will be no external upset to prevent the CT from passing through the Stuffing Box. If this situation occurs, stop injector before CT passes through the chains and shut in Shear Seal rams on upper BOP's.

If it is thought that the BHA may be lost while down hole, stop the CT at 300ft from surface. Slowly close in the swab valve counting the number of turns. If the CT is still deemed to be across the wellhead, POOH the CT no more than the distance between the top of the wellhead and the top of the CT BOP's. Repeat this step until the swab valve can be fully shut. Once the swab valve is shut, bleed off the pressure in riser.

CT COLLAPSED AT SURFACE

Collapsed CT at surface will be obvious by escape of well bore fluids from the Stuffing Box, as the strippers will no longer seal round the deformed pipe. In addition to this the collapsed pipe will not allow the Injector Head to grip the CT due to its change in shape. Usually collapsed CT will not pull through the bottom brass bushings on the Stuffing Box.

1. If POOH, immediately run CT back in well a sufficient distance to make sure round pipe is in contact with the Stuffing Box.
2. Call alert and notify client representative.
3. Ensure that all non-essential personnel are cleared from the immediate area.
4. Immediately reduce well head pressure by all safe means possible; either flow well through choke at a higher rate or stop annular fluid injection if reverse circulating.
5. Increase CT internal pressure by circulating.
6. Once pressure conditions inside and outside the CT have been optimized, a decision can be taken on how to proceed. If it is not possible to position un-collapsed pipe across the stripper rubbers, i.e., well contents are escaping from stripper rubbers:
7. Call alert and notify client representative.
8. Close pipe rams in an effort to reduce flow of fluid/gas around CT.

Note: If it is not possible to control the well, the slips will have to be set, and the CT cut using the Shear Seal rams.

9. Arrange for clamps to be fitted to CT above Injector Head.
10. Remove all non-essential personnel from immediate area
11. Under authority from client representative, kill well.
12. Release pressure from Stuffing Box and remove bushings.
13. Open pipe rams.
14. Attempt to pull CT from the well using the Injector Head.
15. Cut CT at the gooseneck and use the rig or a crane to pull the CT through the injector. Re-clamp the CT above the Injector Head and cut off in thirty-foot sections (or as appropriate to the crane or rig)
16. Continue pulling and cutting CT until the CT pulled to surface can be pulled by the Injector Head.
17. Once CT in good condition (i.e. not collapsed) is at surface, set CT slips and pipe rams and make up roll-on connector to CT on reel.
18. Continue POOH.

If the leak is too serious and cannot be controlled and well fluids are escaping, continue as per Section 9.2.

CT BREAKS AT SURFACE

If CT breaks at surface into two separate sections:

1. Stop the injector and set the slips.
2. Stop pumping operations.
3. Call alert and notify client representative. Ensure all non-essential personnel are cleared from the area and that the area is secure.
4. Secure CT reel.
5. If the reel capacity is insufficient to hold all of the CT remaining in the well due to uneven spooling resulting from the CT failure, it may be necessary to obtain another reel with sufficient capacity to hold the CT remaining in the well.
6. After consulting with client representative, remove damaged section of CT and insert in line roll-on connector and continue to POOH.
7. If this course of action is considered inappropriate or dangerous due to well conditions or condition of CT still in the well, continue as per Section 0.

BUCKLED TUBING

Should the CT hit an obstruction down hole while RIH with the thrust pressure set too high or running speed too fast, the CT will buckle in a 'Z' shape (plastically hinged).

CT being run inside CT and through small ID BOP's/lubricators will normally buckle between the Stuffing Box and the chains.

CT being run through casing or open hole will normally break below the BOP, usually somewhere around the largest ID.

- The CT will generally buckle several times.
- This type of failure is a little more difficult to detect.

If the CT is being run into casing and a large amount of weight is lost suddenly, there is a very good possibility that the CT is buckled somewhere down hole. Indications of this could be:

- An increase in pump pressure as fluid or gas is now being pushed through an additional restriction created by a hinge.
- A decrease in pump pressure as the CT may have broken removing a restriction such as a BHA.
- A loss of string weight due to the CT breaking and falling off.
- An increase in string weight while pulling out of the hole as the buckled portion of CT creates additional drag or needs to be straightened to get through a restricted ID.

In the event CT buckling is suspected, the CT movement should be stopped and the pump pressure kept within operating limits allowing the situation to be analyzed and determine the correct action to be taken for existing conditions.

If there is an increase in pump pressure or an increase in string weight:

1. Stop the pumps and pick up slowly.
2. POOH slowly (10 to 20 feet per minute) watching the weight indicator carefully.
3. If the CT is buckled close to surface, the buckled CT will pull into the bottom of the Stuffing Box and stop.
4. Close and lock the slip and pipe rams.
5. If the ram indicators show that the rams are not completely closed, there may be more than one piece of CT inside the BOP. In this event, open the rams and try to put undamaged CT across the pipe and slip rams.

6. Make arrangements to kill the well and retrieve the remaining CT from the well.
7. If the buckled CT is down hole and cannot be pulled free, consult the client representative as he may want the CT left at TD prior to being hung off in the slip and CT rams.
8. Arrangements should be made to run CT cutter on wireline to retrieve the CT above stuck point.

If there is a decrease in pump pressure or a loss of string weight:

1. It must be assumed that the CT has parted somewhere down hole.
2. Calculate from the remaining string weight approximately how much CT is left in the well.
3. Stop the pumps and POOH slowly.
4. Should the CT come out of the Stuffing Box, the blind rams should also be closed in.

If the CT is buckled above the Stuffing Box, the following steps should be taken:

1. Stop the injector as quickly as possible.
2. Close the slip and pipe rams and manually lock them.
3. If the down hole check valves are holding, bleed the pressure in the CT down to zero and monitor for 15 minutes for pressure build up.
4. Consider at this stage whether to kill the well.
5. Use a hacksaw to start the cut until you are sure there is no trapped pressure in the CT.
6. Cut the CT
7. Remove as much of the buckled CT as possible leaving any undamaged CT showing above the Stuffing Box intact so that it may be rejoined later.
8. Bleed the pressure from above the CT rams and undo the connection below the injector.
9. Slowly raise the injector until it is clear of the damaged CT.
10. Cut away any damaged CT, dress the CT and install an inline connector.
11. Run some fresh CT down through the injector until it is just out of the Stuffing Box.
12. Lower the injector until immediately over the pipe sticking out of the BOP.
13. Attach the pipe to the inline connection attached to the pipe sticking up out of BOP.
14. Pump off the inside chain tension and rotate the chains slowly in the OOH direction, while lowering the injector until the connection below the injector can be fastened.
15. Pump up the inside chain tension and pull weight equal to the weight of the CT suspended below the slips plus 2,000 lbf for friction or CERBERUS prediction, whichever is greatest.
16. Equalize the pressure across the CT rams.
17. Unlock the pipe and slip rams.
18. Open the slip and pipe rams and POOH.
19. If the down hole check valves do not hold then the CT will have to be cut.

CT STUCK IN HOLE PROCEDURES

There are various scenarios by which CT can be deemed as a stuck in hole situation. The following procedures are to be used as generic guidelines prior to the compilation of a signed off chemical cutting program applicable to the current situation.

In the event of being stuck in hole, several factors would have to be taken into consideration, the first of which would be whether the CT is stuck in hole on a platform, or a semi-submersible, as the procedures to be followed may vary greatly between the two options.

Other factors to be considered are:

- Type of well, i.e., flowing oil or gas well, water injector etc.
- The type of BHA being used, i.e., perforating guns, milling assembly, plug etc.
- The type of operation being carried out when the CT became stuck.

In all of the above cases, the CT would be defined as being “stuck” when the pipe cannot be retrieved from the well bore without the pipe exceeding its 80% minimum yield rating, or without exceeding 80% stress of the weak link release rating. The lower of these two factors should always be used when attempting large pulls.

Regardless of the specifics involved, the following procedures should be adopted:

1. Inform the client representative of the situation.
2. Inform the Onshore Engineer.
3. From the information available, and taking into account the well conditions, try to determine the reason for the pipe/BHA being stuck.
4. Attempt to pull free by applying a steady pull to a maximum of 80% of the CT yield. If in doubt as to what this figure is, consult Engineering Department before proceeding.
5. When applying the maximum pull, hold the maximum value for a minimum of 10 minutes and observe the trend (if any) on the weight indicator and chart. Measure the amount of pipe extension that is required when this pull is applied. The figure can be used to determine where the CT is stuck. As a rule of thumb, the depth that the pipe is held at will be the extension of the CT (in feet) when pulled to 80% of yield divided by 0.002. This can be determined using CERBERUS.

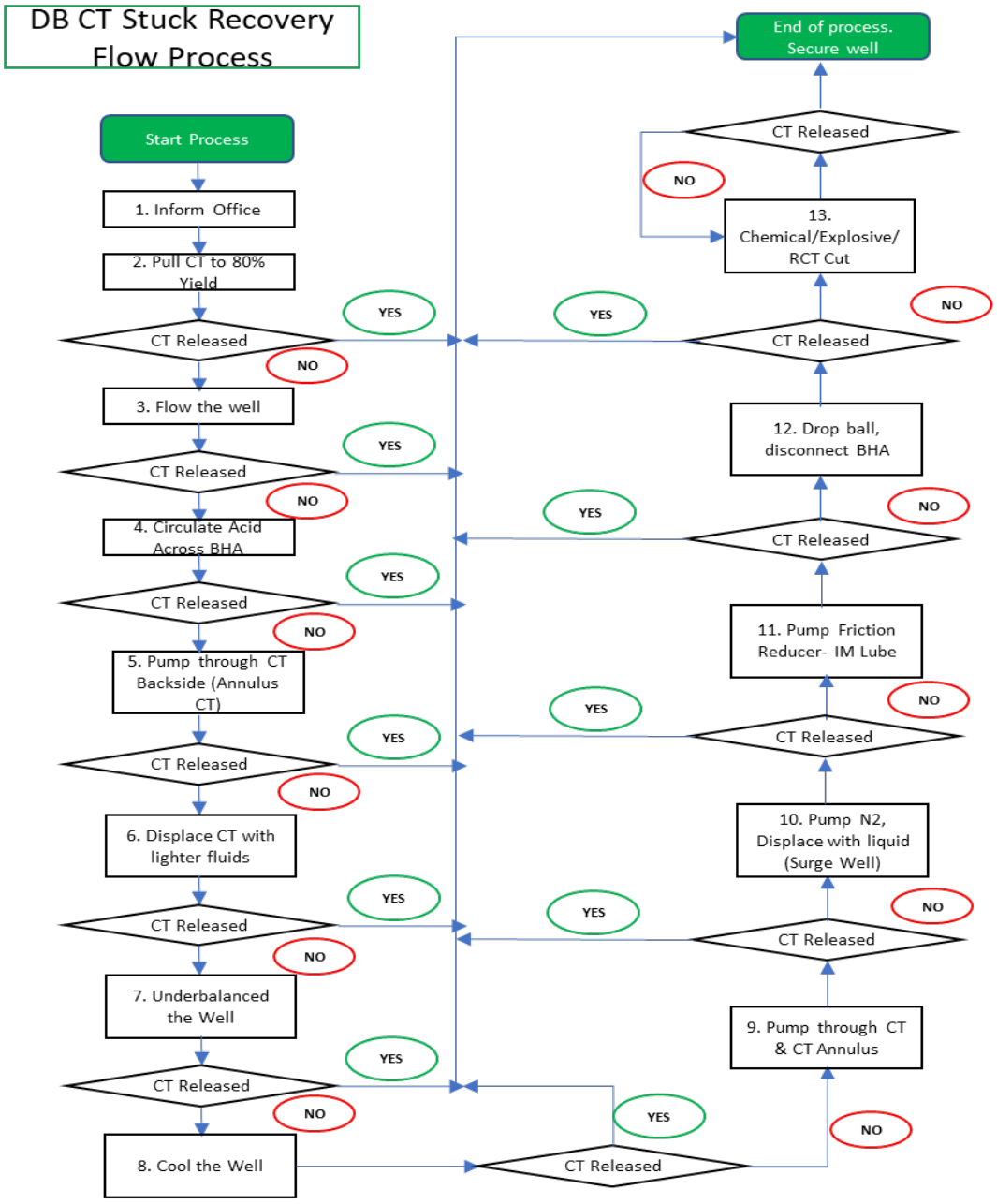
The following are options that may be appropriate depending on the particular circumstances:

1. If possible, flow the well, or increase well flow in an effort to remove debris in the well bore that may be holding the CT/BHA. Maintain maximum circulation through the CT at the same time. This is particularly relevant if well cleanout or drilling operations have been performed.
2. Circulate acid across the BHA in an attempt to remove any acid soluble material that may be holding the CT.
3. Pump fluid down the backside of the CT to the formation in an attempt to dislodge debris from around the BHA. Potential CT collapse must be considered if engineering this scenario.
4. Displace CT contents to a lighter fluid (base oil) or gas (Nitrogen) to increase buoyancy and allow greater end force to be applied at BHA.
5. Underbalance the well in the case of differentially stuck CT.
6. Cool the well if the CT is helically stuck in corkscrewed Production Tubing.
7. Pump down the CT / completion annulus to try and move the source of hold-up.
8. Displace slugs of Nitrogen with water to create a surge effect at the BHA.
9. Pump friction reducer, IM Lube in seawater at 2-3% by volume, down the CT and into the well. Ideally, one well volume will be pumped.

10. After consultation with the client representative and the on-call Engineer, activate the emergency disconnect mechanism in the BHA to allow the CT to be released. The release mechanism should only be implemented after all avenues have been explored.
11. When attempting maximum pull, do not work the CT violently across the gooseneck by frequent intervals.
12. The number of cycles across the gooseneck must be logged, and if in doubt of the CT fatigue condition, the Engineer must be consulted and the cycles entered into the CERBERUS FATIQUE program, to determine the number of cycles left available.

After consultation with the client representative, kill the well and commence preparations for chemical cutting operations.

STUCK CT COIL RECOVERY PROCESS



Precautionary Steps to avoid Stuck while Cleanout in Dual string Completion:

1) To monitor pressure trending all the times during operation and record for any abnormalities. If there is continue pressure increasing trend during cleanout, proceed to pick up coil to the previous pull test depth and perform flow rate test.
2) In the event of coil entangle on the Long string, proceed to pick up coil and simulate pumping lost prime scenario to create vibration and tip of coil wobble to release from entanglement.

APPENDIX V – DOWNHOLE TOOL SPECS

2-1/8" SpinCat Nozzle

STONEAGE SPINCAT™ SC-212

The StoneAge SpinCat™ SC-212 can be used at operating pressures of 1000 to 5000 psi and flow rates of 0.8 to 2 bpm (32 to 80 gpm). It has a 1 1/2" AMMT inlet thread.

Tool Family	StoneAge SpinCat™	
Tool Model	SC-212	
Pressure Range	1-5k psi	70-340 bar
Flow Range	0.8-2.0 bpm	32-80 gpm
Flow Rating	4.6 Cv	
Rotation Speed	150-200 rpm	
Inlet Connection	1-1/2" AMMT	
PSI Loss (@ 1 bpm)	83 psi	6 bar
Tension (pull)	Safe load to 15000 lbs	6804 kg
Compression (set down)	Safe load to 21000 lbs	9525 kg
Outside Diameter	2.12 in.	5.4 cm
Overall Length	12.3 in.	31.2 cm
Weight	8.9 lbs	4 kg
Maximum Temperature	390° F	200° C

APPENDIX VI – CIRCA SIMULATION

Cleanout from depth 1,573 m MDTHF to 2,248 m MDTHF (EOT)

➢ Flow Summary (With 1,072 psi Reservoir Pressure from E-10/11)

SUMMARY OF FLOW RESULTS

Produced Fluids	
Pressure known at:	Perforations
Production Mode:	No Production
Fluid Composition:	Gas Only
Circulated Fluids	
Fluid Composition:	Nitrified Water
Liquid:	0.90 bbl/min
Solids:	0.00 bbl/min
Gas:	300.0 scf/min
Circulation Point:	2248.60 m
HHP Required :	80.37 HP

COMPLETION:

Wellhead Pressure	83.9 psi g
Hydrostatic pressure loss	716.6 psi
Friction pressure loss	276.9 psi
Kinetic pressure loss	-5.8 psi
Restriction pressure loss	0.3 psi
Equivalent Circulation Density[ECD]	5.42 lb/gal (US)
Perforation Pressure	1072.0 psi g
Hydrostatic pressure loss	509.4 psi
Bottom Hole Pressure	1581.4 psi g
FROM CIRCULATION POINT TO WELLHEAD:	
Liquid transit time	16 min
Gas transit time	13 min
Annular volume	47.9 bbl
Volume below circulation point	105.2 bbl
Total liquid volume	125.9 bbl
Total gas volume	27.2 bbl
(Surface equivalent)	4919.5 scf

WORKSTRING:

Liquid:	1296.0 bbl/day
Gas:	300 scf/min
Pressure at reel rotating joint	3629.8 psi g
Friction pressure loss on reel	2064.8 psi
Hydrostatic pressure loss on reel	7.4 psi
Pressure inside WS at Gooseneck	1557.6 psi g
Hydrostatic pressure loss	-885.4 psi
Friction pressure loss	1324.7 psi
Equivalent Circulation Density[ECD]	2.60 lb/gal (US)
BHA total pressure loss	126.4 psi
BHA Hydrostatic loss	-0.8 psi
BHA Friction loss	10.1 psi
BHA Kinetic loss	2.3 psi
Nozzle	114.9 psi
Circulation Point pressure	991.9 psi g
FROM REEL ROTATING JOINT TO CIRCULATION POINT:	
Liquid transit time	18 min
Gas transit time	18 min
Displacement Volume	16.1 bbl
Internal Volume	24.3 bbl
Internal liquid volume	16.0 bbl
Internal gas volume	8.3 bbl
(Surface equivalent)	5480.0 scf
Length of Workstring on reel	2624.81 m

➢ Cleanout Summary (With 1,072 psi Reservoir Pressure from E-10/11)

SUMMARY OF HOLE CLEANING RESULTS

Initial Condition:	
% of fill interval occupied by solids before cleanout	50.0 %
Top of fill	1573.01 m
Deepest Circulation point	2248.60 m
Bottom of fill	2248.60 m
Initial Volume of Solids	9.6 bbl
Initial Mass of Solids	4938.8 lb
Solids type:	Mud Residue/Formation Fines
Fluid Description:	Nitrified Water
Penetration Hole Cleaning Mode:	
Penetration rate	10.0 ft/min
Penetration time	3.69 hr
Solids volume in the well after penetration	9.5 bbl
Solids mass in the well after penetration	4853.6 lb
Circulation Hole Cleaning Mode:	
Hole circulation time	10.00 hr
Solids volume in the well after circulation	1.5 bbl
Solids mass in the well after circulation	758.9 lb
Wiper Trip Hole Cleaning Mode:	
Wiper Trip Scheme:	User Specified rate, Tornado not
Wiper trip time	6.00 hr
Solids volume in the well after wiper trip	0.1 bbl
Solids mass in the well after wiper trip	44.8 lb

Volume of Fluids Pumped During Penetration, Circulation & Wiper Trip:

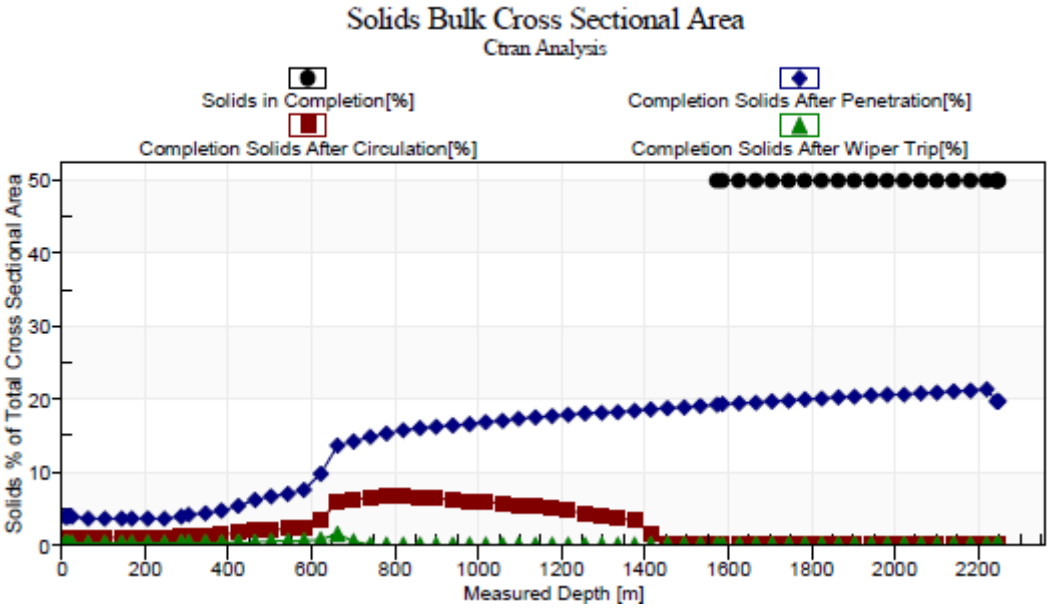
Gas volume	354487.7 scf
Liquid Volume	1063.5 bbl
Penetration, Circulation & Wiper Trip time	19.69 hr

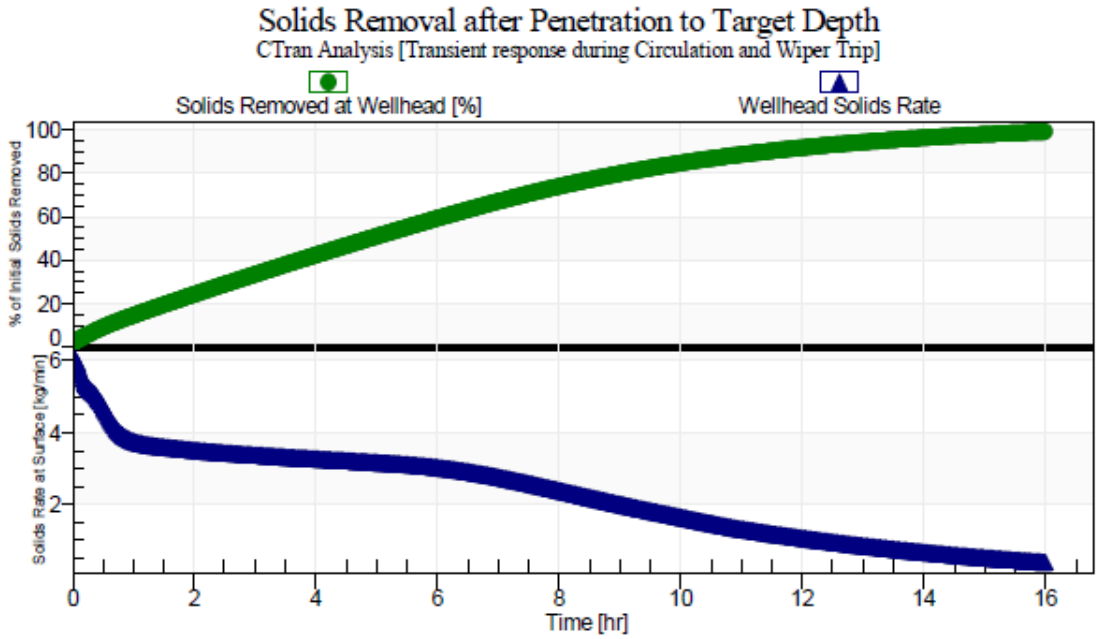
Summary for cleanout :-
Top HUD: 1,573 m MDTHF
Bottom HUD: 2,248 m MDTHF (EOT)
Pump rate – 0.9 bpm with 300 scfm (Nitrified TIW)
Penetration speed – 10ft/min
Circulation time – 10 Hours at depth EOT
Wiper trip speed – 10 ft/min until 1,150 m MDTHF

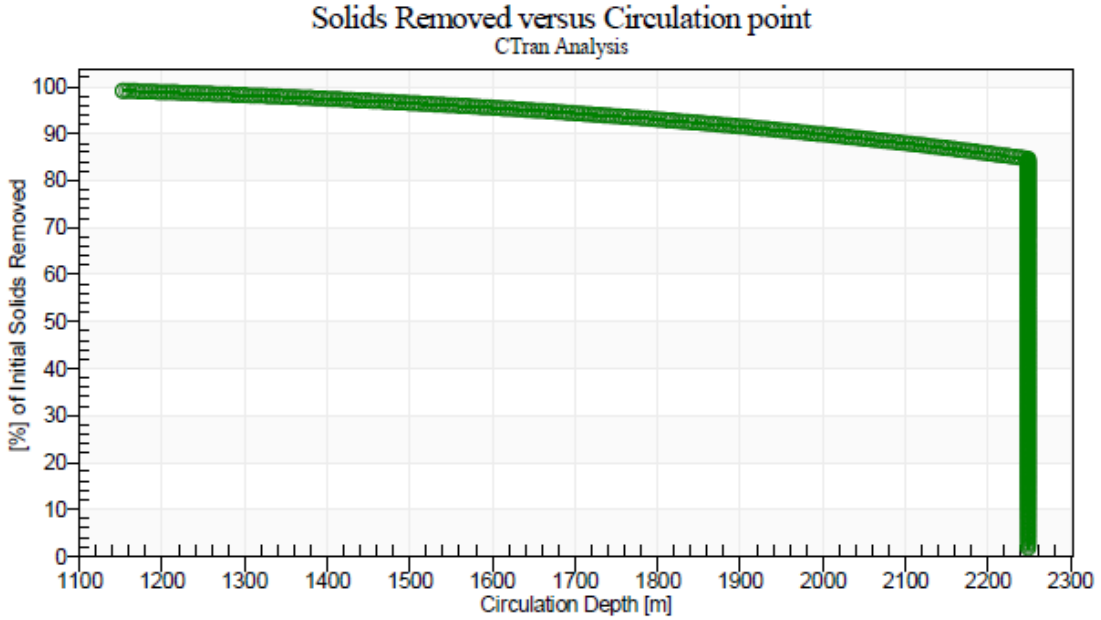
Cleanout success with only 0.9 % solid left in hole from 50% (assumption).

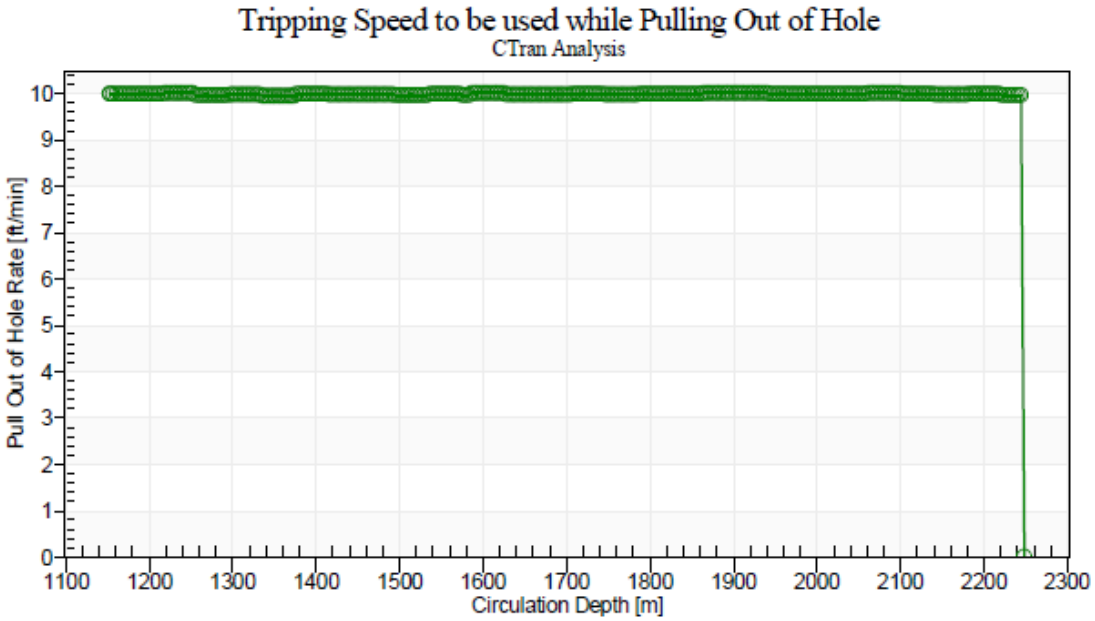
Flow State (continued)

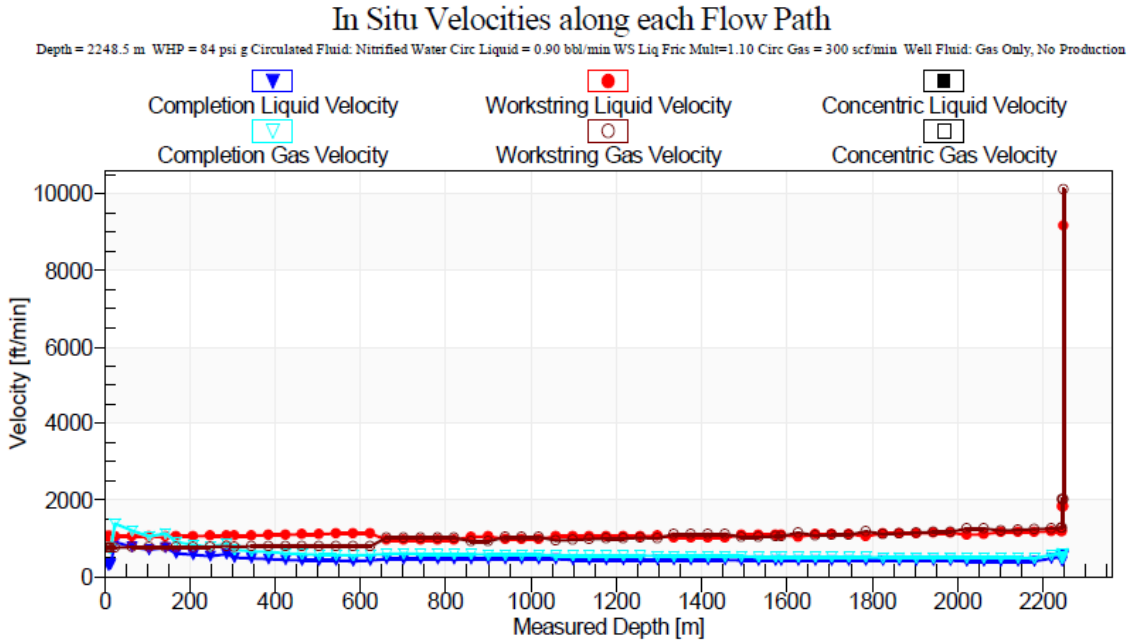
Measured Depth[Flow] m	Temperature	Completion Pressure	Workstring Pressure	Concentric Pressure	Completion Liquid Velocity hr	Workstring Liquid Velocity m	Concentric Liquid Velocity ft/min
1573.0	186.7	758.4	1420.1	0.0	424	1092	0
1586.5	187.2	762.7	1413.4	0.0	423	1095	0
1626.1	188.9	776.0	1407.8	0.0	422	1035	0
1665.8	190.5	789.3	1392.2	0.0	420	1104	0
1705.4	192.1	802.4	1372.3	0.0	419	1107	0
1745.0	193.7	815.8	1352.3	0.0	418	1113	0
1784.6	195.4	829.4	1346.3	0.0	416	1055	0
1824.3	197.0	842.8	1325.8	0.0	415	1121	0
1863.9	198.7	856.2	1304.8	0.0	414	1123	0
1903.5	200.3	869.6	1283.3	0.0	413	1128	0
1943.1	201.9	883.1	1261.6	0.0	412	1135	0
1982.8	203.6	896.9	1239.8	0.0	410	1145	0
2022.4	205.3	911.3	1233.2	0.0	409	1094	0
2062.0	207.1	925.7	1226.5	0.0	408	1097	0
2101.6	208.8	939.9	1204.3	0.0	407	1160	0
2141.3	210.5	954.0	1181.3	0.0	406	1164	0
2180.9	212.2	968.0	1157.7	0.0	405	1168	0
2220.5	213.9	981.9	1133.4	0.0	479	1175	0
2243.6	214.8	990.1	1119.0	0.0	509	1179	0
2244.9	214.9	990.5	1118.2	0.0	404	1179	0
2245.0	214.9	990.4	1115.5	0.0	542	1831	0
2245.8	214.9	990.7	1113.7	0.0	542	1832	0
2247.3	215.0	991.4	1109.9	0.0	542	1834	0




Solids Removal after Penetration to Target Depth
CTran Analysis [Transient response during Circulation and Wiper Trip]
Solids Removed at Wellhead [%]
Wellhead Solids Rate
% of Initial Solids Removed
Solids Rate at Surface [kg/min]
Time [hr]


Solids Removed versus Circulation point
CTran Analysis
[%] of Initial Solids Removed
Circulation Depth [m]


Tripping Speed to be used while Pulling Out of Hole
CTran Analysis
Pull Out of Hole Rate [ft/min]
Circulation Depth [m]
0
1
2
3
4
5
6
7
8
9
10
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300


In Situ Velocities along each Flow Path
Depth = 2248.5 m WHP = 84 psi g Circulated Fluid: Nitrified Water Circ Liquid = 0.90 bbl/min WS Liq Fric Mult=1.10 Circ Gas = 300 scf/min Well Fluid: Gas Only, No Production
Completion Liquid Velocity
Workstring Liquid Velocity
Concentric Liquid Velocity
Completion Gas Velocity
Workstring Gas Velocity
Concentric Gas Velocity
Velocity [ft/min]
Measured Depth [m]
0
2000
4000
6000
8000
10000
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200

Neu Dimension
Your Integrated Solutions Partner

Sensitivity Analysis – Fill %

Constant parameter

- 1.5" CT String
- Pump Rate = 0.9 bbl/min 300 scf/min
- Top of fill= 1,573 m MDTHF, Bottom of fill= 2,248 m MDTHF
- Perforation Pressure= 1,072 psi

Fill %	Circulating Pressure	Cleanout Time				Solid left in completion	Remarks
	Pressure at Rotating Joint	Penetration Hour	Circulation Hour	Wiper trip Hour	**Total Hours**	%	
25%	3,630	3.69	10	6	**19.69**	**4.3**	Able to cleanout. Reduce wiper trip speed to improve cleanout efficiency.
50%	3,630	3.69	10	6	**19.69**	**0.9**	Able to cleanout. Reduce wiper trip speed to improve cleanout efficiency.
75%	2,071	3.69	10	6	**19.69**	**21.3**	Loss return if using 0.9 bbl/min 300 scf/min. However, we recommend to reduce pump rate to **0.5 bpm & 300 scf/min** during wiper trip for every 30 m penetration

30

Client: **PCSB**
Well: **D-22**
Field: **Dulang D**
Job: **Sand Cleanout from 1,573 m until EOT at 2,248 m MDTHF**
Date: **23/3/2024**

Dimension Bid (M) Sdn Bhd
Time Planner

Total Time 37:39 hh:mm

BBLS	GAL N2
1,649.2	6,325.5

No.	Stage	Fluid Used	Time, hh:mm			Fluids		Tripping			Totals	
			Start	End	Stage	BPM	SCFM	From	To	ft/min	BBLS	GAL N2
1	CT RIH to 10m above HUD at 1,563m MDTHF	FLUID 1 - TIW	4:00	6:50	2:50	0.3	0	0	5,128	30.0	51.3	0
2	Increase pump rate to establish return on surface prior penetrate HUD at 1,444 m MDDF	FLUID 2 - Nitrified	6:50	8:02	1:11	0.9	300	5,128	5,128	0.0	64.0	229
3	Start Penetrate HUD 30m/100ft	FLUID 2 - Nitrified	8:02	8:12	0:10	0.9	300	5,128	5,228	10.0	9.0	32
4	Circulate 5bbls Gel	FLUID 3 - Gel	8:12	8:17	0:05	0.9	300	5,228	5,228	0.0	5.0	18
5	Wiper Trip to 10m above previous HUD	FLUID 2 - Nitrified	8:17	8:30	0:13	0.9	300	5,228	5,098	10.0	11.7	42
6	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	8:30	8:53	0:23	0.9	300	5,098	5,328	10.0	20.7	74
7	Circulate 5bbls Gel	FLUID 3 - Gel	8:53	8:59	0:05	0.9	300	5,328	5,328	0.0	5.0	18
8	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	8:59	9:12	0:13	0.9	300	5,328	5,198	10.0	11.7	42
9	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	9:12	9:35	0:23	0.9	300	5,198	5,428	10.0	20.7	74
10	Circulate 5bbls Gel	FLUID 3 - Gel	9:35	9:40	0:05	0.9	300	5,428	5,428	0.0	5.0	18
11	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	9:40	9:53	0:13	0.9	300	5,428	5,298	10.0	11.7	42
12	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	9:53	10:16	0:23	0.9	300	5,298	5,528	10.0	20.7	74
13	Circulate 5bbls Gel	FLUID 3 - Gel	10:16	10:22	0:05	0.9	300	5,528	5,528	0.0	5.0	18
14	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	10:22	10:35	0:13	0.9	300	5,528	5,398	10.0	11.7	42
15	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	10:35	10:58	0:23	0.9	300	5,398	5,628	10.0	20.7	74
16	Circulate 5bbls Gel	FLUID 3 - Gel	10:58	11:03	0:05	0.9	300	5,628	5,628	0.0	5.0	18
17	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	11:03	11:16	0:13	0.9	300	5,628	5,498	10.0	11.7	42
18	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	11:16	11:39	0:23	0.9	300	5,498	5,728	10.0	20.7	74
19	Circulate 5bbls Gel	FLUID 3 - Gel	11:39	11:45	0:05	0.9	300	5,728	5,728	0.0	5.0	18
20	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	11:45	11:58	0:13	0.9	300	5,728	5,598	10.0	11.7	42
21	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	11:58	12:21	0:23	0.9	300	5,598	5,828	10.0	20.7	74
22	Circulate 5bbls Gel	FLUID 3 - Gel	12:21	12:26	0:05	0.9	300	5,828	5,828	0.0	5.0	18
23	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	12:26	12:39	0:13	0.9	300	5,828	5,698	10.0	11.7	42
24	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	12:39	13:02	0:23	0.9	300	5,698	5,928	10.0	20.7	74
25	Circulate 5bbls Gel	FLUID 3 - Gel	13:02	13:08	0:05	0.9	300	5,928	5,928	0.0	5.0	18
26	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	13:08	13:21	0:13	0.9	300	5,928	5,798	10.0	11.7	42
27	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	13:21	13:44	0:23	0.9	300	5,798	6,028	10.0	20.7	74
28	Circulate 5bbls Gel	FLUID 3 - Gel	13:44	13:50	0:05	0.9	300	6,028	6,028	0.0	5.0	18
29	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	13:50	14:03	0:13	0.9	300	6,028	5,898	10.0	11.7	42
30	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	14:03	14:26	0:23	0.9	300	5,898	6,128	10.0	20.7	74
31	Circulate 5bbls Gel	FLUID 3 - Gel	14:26	14:31	0:05	0.9	300	6,128	6,128	0.0	5.0	18
32	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	14:31	14:44	0:13	0.9	300	6,128	5,998	10.0	11.7	42
33	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	14:44	15:07	0:23	0.9	300	5,998	6,228	10.0	20.7	74
34	Circulate 5bbls Gel	FLUID 3 - Gel	15:07	15:13	0:05	0.9	300	6,228	6,228	0.0	5.0	18
35	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	15:13	15:26	0:13	0.9	300	6,228	6,098	10.0	11.7	42
36	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	15:26	15:49	0:23	0.9	300	6,098	6,328	10.0	20.7	74
37	Circulate 5bbls Gel	FLUID 3 - Gel	15:49	15:54	0:05	0.9	300	6,328	6,328	0.0	5.0	18
38	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	15:54	16:07	0:13	0.9	300	6,328	6,198	10.0	11.7	42
39	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	16:07	16:30	0:23	0.9	300	6,198	6,428	10.0	20.7	74
40	Circulate 5bbls Gel	FLUID 3 - Gel	16:30	16:36	0:05	0.9	300	6,428	6,428	0.0	5.0	18
41	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	16:36	16:49	0:13	0.9	300	6,428	6,298	10.0	11.7	42
42	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	16:49	17:12	0:23	0.9	300	6,298	6,528	10.0	20.7	74
43	Circulate 5bbls Gel	FLUID 3 - Gel	17:12	17:17	0:05	0.9	300	6,528	6,528	0.0	5.0	18
44	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	17:17	17:30	0:13	0.9	300	6,528	6,398	10.0	11.7	42
45	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	17:30	17:53	0:23	0.9	300	6,398	6,628	10.0	20.7	74
46	Circulate 5bbls Gel	FLUID 3 - Gel	17:53	17:59	0:05	0.9	300	6,628	6,628	0.0	5.0	18
47	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	17:59	18:12	0:13	0.9	300	6,628	6,498	10.0	11.7	42
48	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	18:12	18:35	0:23	0.9	300	6,498	6,728	10.0	20.7	74
49	Circulate 5bbls Gel	FLUID 3 - Gel	18:35	18:40	0:05	0.9	300	6,728	6,728	0.0	5.0	18
50	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	18:40	18:53	0:13	0.9	300	6,728	6,598	10.0	11.7	42
51	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	18:53	19:16	0:23	0.9	300	6,598	6,828	10.0	20.7	74
52	Circulate 5bbls Gel	FLUID 3 - Gel	19:16	19:22	0:05	0.9	300	6,828	6,828	0.0	5.0	18
53	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	19:22	19:35	0:13	0.9	300	6,828	6,698	10.0	11.7	42
54	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	19:35	19:58	0:23	0.9	300	6,698	6,928	10.0	20.7	74
55	Circulate 5bbls Gel	FLUID 3 - Gel	19:58	20:03	0:05	0.9	300	6,928	6,928	0.0	5.0	18
56	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	20:03	20:16	0:13	0.9	300	6,928	6,798	10.0	11.7	42
57	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	20:16	20:39	0:23	0.9	300	6,798	7,028	10.0	20.7	74
58	Circulate 5bbls Gel	FLUID 3 - Gel	20:39	20:45	0:05	0.9	300	7,028	7,028	0.0	5.0	18
59	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	20:45	20:58	0:13	0.9	300	7,028	6,898	10.0	11.7	42
60	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	20:58	21:21	0:23	0.9	300	6,898	7,128	10.0	20.7	74
61	Circulate 5bbls Gel	FLUID 3 - Gel	21:21	21:27	0:05	0.9	300	7,128	7,128	0.0	5.0	18
62	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	21:27	21:40	0:13	0.9	300	7,128	6,998	10.0	11.7	42
63	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	21:40	22:03	0:23	0.9	300	6,998	7,228	10.0	20.7	74
64	Circulate 5bbls Gel	FLUID 3 - Gel	22:03	22:08	0:05	0.9	300	7,228	7,228	0.0	5.0	18
65	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	22:08	22:21	0:13	0.9	300	7,228	7,098	10.0	11.7	42
66	RIH HUD + 30m/100ft (CT at 2,248 m @ EOT)	FLUID 2 - Nitrified	22:21	22:49	0:27	0.9	300	7,098	7,376	10.0	25.0	90
67	Circulate 40 bbls Gel	FLUID 3 - Gel	22:49	23:33	0:44	0.9	300	7,376	7,376	0.0	40.0	143
68	CBU for 10 hours. Flag #1 CT at surface at depth 2,248 m @ EOT	FLUID 2 - Nitrified	23:33	9:33	10:00	0.9	300	7,376	7,376		540.0	1,933
69	Pick up CT to 2,243 m MDTHF & flag #2 CT at surface at 2,243 m MDTHF ('D' Nogo Nipple)	FLUID 2 - Nitrified	9:33	9:35	0:01	0.9	300	7,376	7,359	10.0	1.5	5
70	Wiper Trip to Nippleless Plug @ 2,200 m	FLUID 2 - Nitrified	9:35	9:49	0:14	0.9	300	7,359	7,218	10.0	12.7	45
71	Continue Wiper Trip to 1,150 m MDTHF	FLUID 2 - Nitrified	9:49	15:34	5:44	0.3	300	7,218	3,773	10.0	103.4	1,110
72	POOH to surface	FLUID 1 - TIW	15:34	17:39	2:05	0.3		3,773	0	30.0	37.7	

APPENDIX VII – DECISION TREE