DIMENSION BID

PETRONAS

DULANG D-31
SCALE CLEANOUT & NEAR WELLBORE ACID WASH

Revision: 2
Prepared for: Pravin Nair Venugopalan
Date Prepared: 16th June 2024
Well: D-31
Field: Dulang D
Operation Region: PMA
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DESIGN VERIFICATION

PREPARED BY DB CTS Field Engineer	 Muhd Ameerul Zaeem	16/06/2024 Date
REVIEWED BY DB CTS Technical Advisor	 Kung Yee Han	16/06/2024 Date
APPROVED BY DB CTS General Manager	 Aliff Adenan	16/06/2024 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	13/6/2024	M. Ameerul Zaeem
1	Change cleanout fluid to injection water & include pumping sequence during spotting 5 bbls of 15% HCl acid on top of 1,855 m MDTHF in CT Run#1	13/6/2024	M. Ameerul Zaeem
2	Revise job step in CT Run#1	16/6/2023	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
OHSAS	Open Hole Stand Alone Screen
TIW	Treated Injection Water
TFW	Treated Fresh Water
IW	Injection Water
SSD	Sliding Side Door

TABLE OF CONTENT

OBJECTIVES

The objective of this job is:

1) To perform scale cleanout and clear HUD (scale) inside completion tubing from 1,855 m MDTHF until 1,973 m MDTHF.
2) To perform near wellbore acid wash of E10-11 & E12-13 via bullheading to tackle mainly on the calcite scale issue.

Therefore, this CTU operation consists of 1 CT run & bullheading acid wash with 1 contingency (CT Scale Cleanout).

BACKGROUND

Dulang D-31 is an oil producer with single string completion with combination of 3-1/2" & 2-7/8" completion tubing which was completed on May 2012 with maximum deviation of 56 degree at 748.51 m MDRKB. Currently the well is flowing commingle from E6, E10-11, E12-13A & E12-13B with liquid rate of 514 bpd & 83% water cut. The well is underperforming due to restriction at 1,855 m MDTHF during TCC & recovered scale sample after bailing. PCSB has engaged DB to perform Scale Cleanout from latest HUD at 1,855 m MDTHF until 1,973 m MDTHF.

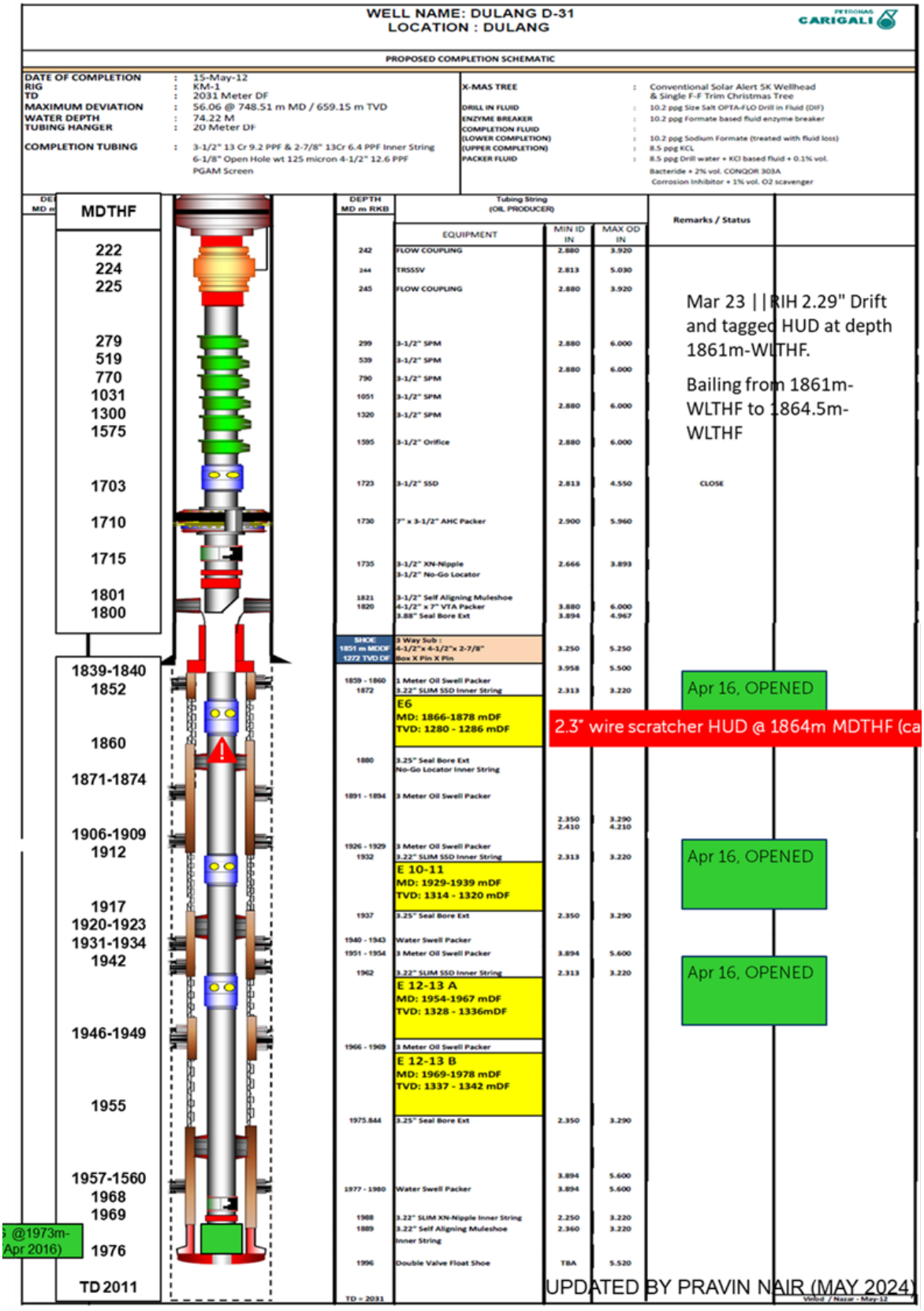
WELL DATA

Input Parameter	Parameter Value
Field	Dulang D-31
Max. Deviation (degrees)	58 Deg @ 1,232 m MDTHF
Min. Restriction (inch)	2.25” (XN Nipple) @ 1,968 m MDTHF
Tubing Specification	3-1/2” & 2-7/8” Production Tubing (Refer Well Schematic)
Type of Fluid & Density	N/A
Top of Fluid	No fluid level detected
Current Well Status	Flowing
Depth of zone	E6 (1,866 – 1,878 m MDDF) E10-11 (1,929 – 1,939 m MDDF) E12-13A (1,954 – 1,967 m MDDF) E12-13B (1,969 – 1,978 m MDDF)
Reservoir Pressure (psi)	E6: 950 psi E10-11: 1,350 psi E12-13A: 1,350 psi E12-13B: 1,350 psi
Reservoir Temperature (deg F)	217 deg F
Porosity	0.2 - 0.3
Permeability (mD)	50 - 200
Fracture Gradient	0.7 psi/ft
H_2S Content	35 ppm
CO_2 Content	60%
Mercury, HG	Not available
Additional Information / Notes / Special Requirement:	
• Latest Scale HUD: 1,855 m MDTHF	

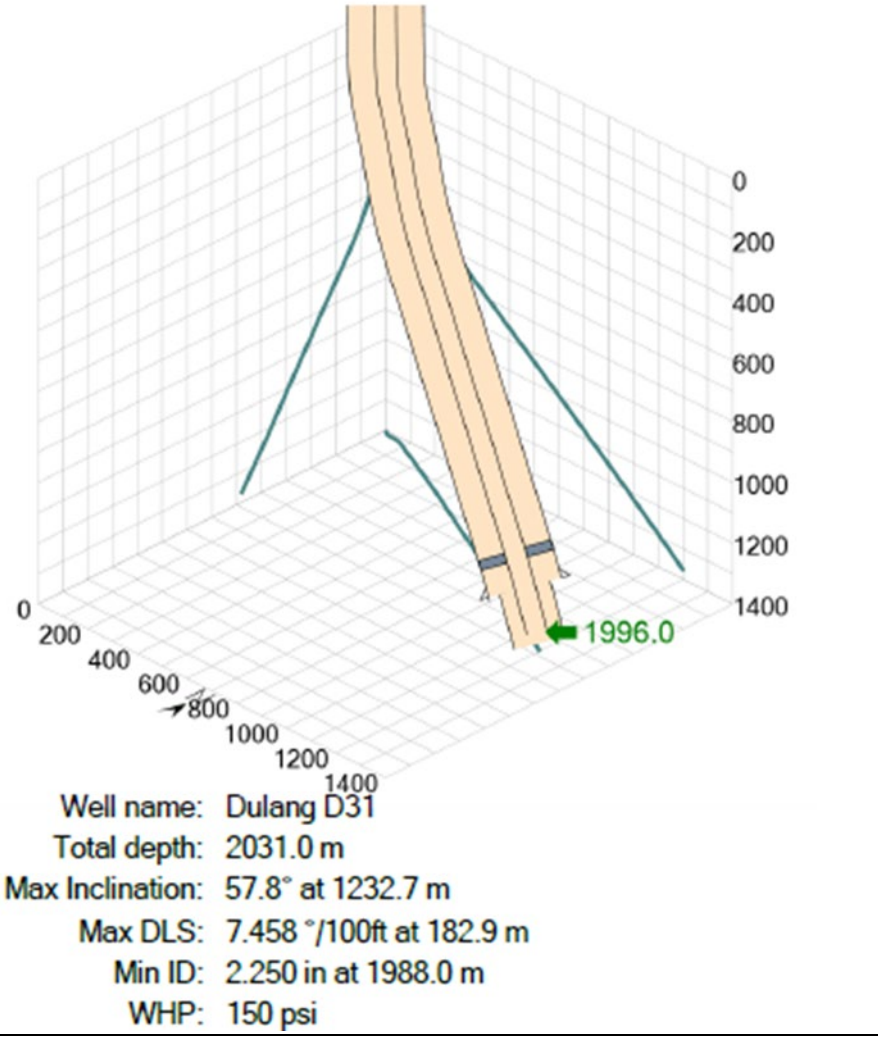
OPERATION SUMMARY

Item	*Job Description*	*Remark*
A	Slickline (Pre CTU)	1. TCC 2. Close SSD#2 (E6) 3. Dummy off SPM#1, SPM#2 & SPM#3
B	Coiled Tubing Operation	CT Run#1 Scale Cleanout from HUD at 1,855 m MDTHF Until 1,973 m MDTHF
C	Slickline	1. TCC 2. Close SSD #2 (E6) & SSD #3 (E10-11)
D	Bullheading	Bullheading#1: Injectivity Test on zone E12-13 Bullheading#2: Near Wellbore Acid Wash Treatment (E12-13)
E	Slickline	1. Close SSD#4 (E12-13) & Open SSD #3 (E10-11)
F	Bullheading	Bullheading#3: Injectivity Test on zone E10-11 Bullheading#4: Near Wellbore Acid Wash Treatment (E10-11)
G	Coiled Tubing Operation	Contingency CT Scale Cleanout

WELL DIAGRAM



WELL 3D PLOT



Input Parameter	*Parameter Value*
Field	Dulang D-31
Trajectory Until Depth	2,031 m MDDF
Max. Deviation (degrees)	57.8 degree at 1,232 m MDDF
Min. Restriction (inch)	2.313” @ 1,872, 1,932 & 1,962 m MDDF

TREATMENT VOLUME

Description	Details
Tubing Specification	3-1/2" 9.2ppf# 13 Cr & 2-7/8" 6.4ppf# 13 Cr
Open Hole Size	6-1/8" Open Hole
OHSAS Screen Specification	4-1/2" 12.6ppf# PGAM Screen

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 SSD#1	3 1/2	2.992	9.2							0.00870	20.00	1703.00	66	5588	**5522**	**48**
SSD#1 to XO	3 1/2	2.992	9.2							0.00870	1703.00	1840.00	5588	6037	**449**	**4**
XO to SSD#2	2 7/8	2.441	6.4							0.00579	1840.00	1852.00	6037	6076	**39**	**0.2**
SSD#2 to SSD#3	2 7/8	2.441	6.4							0.00579	1852.00	1942.00	6076	6372	**295**	**2**
SSD#3 to EOT	2 7/8	2.441	6.4							0.00579	1942.00	1976.00	6372	6483	**112**	**1**
															TOTAL	**63**

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	2 7/8	2.441	6.4				0.06780	20.00	1703.00	66	5588	**5522**	**374**
SSD#1 to Packer#1	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	1703.00	1710.00	5588	5611	**23**	**1**
															TOTAL	**432**

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	
Wellbore at E12-13A	6 1/8	6.125		2 7/8	2.441	6.4				0.02841	1934.00	1946.00	6345	6385	**39**	**1.1**
Wellbore at E12-13B	6 1/8	6.125		2 7/8	2.441	6.4				0.02841	1949.00	1957.00	6395	6421	**26**	**0.7**
Wellbore at E10-11	6 1/8	6.125		2 7/8	2.441	6.4				0.02841	1909.00	1920.00	6263	6300	**36**	**1.0**
															TOTAL	**3**

1 ft Penetration - Zone E 12-13

Type	External Pipe			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E 12-13A Reservoir		30.125		6 1/8			12	0.84512	1954.00	1967.00	6411	6454	**43**	**36**
E 12-13B Reservoir		30.125		6 1/8			12	0.84512	1969.00	1978.00	6460	6490	**30**	**25**
													Porosity	**0.3**
													Total	**18**

2 ft Penetration - Zone E 12-13

Type	External Pipe			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E 12-13A Reservoir		54.125		6 1/8			24	2.80929	1954.00	1967.00	6411	6454	**43**	**120**
E 12-13B Reservoir		54.125		6 1/8			24	2.80929	1969.00	1978.00	6460	6490	**30**	**83**
													Porosity	**0.3**
													Total	**61**

1 ft Penetration - Zone E 10-11

Type	External Pipe			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E 10-11 Reservoir		30.125		6 1/8			12	0.84512	1929.00	1939.00	6329	6362	**33**	**28**
													Porosity	**0.3**
													Total	**8**

2 ft Penetration - Zone E 10-11

Type	External Pipe			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E 10-11 Reservoir		54.125		6 1/8			24	2.80929	1929.00	1939.00	6329	6362	**33**	**92**
													Porosity	**0.3**
													Total	**28**

MAXIMUM ALLOWABLE SURFACE TREATING PRESSURE (MASTP)

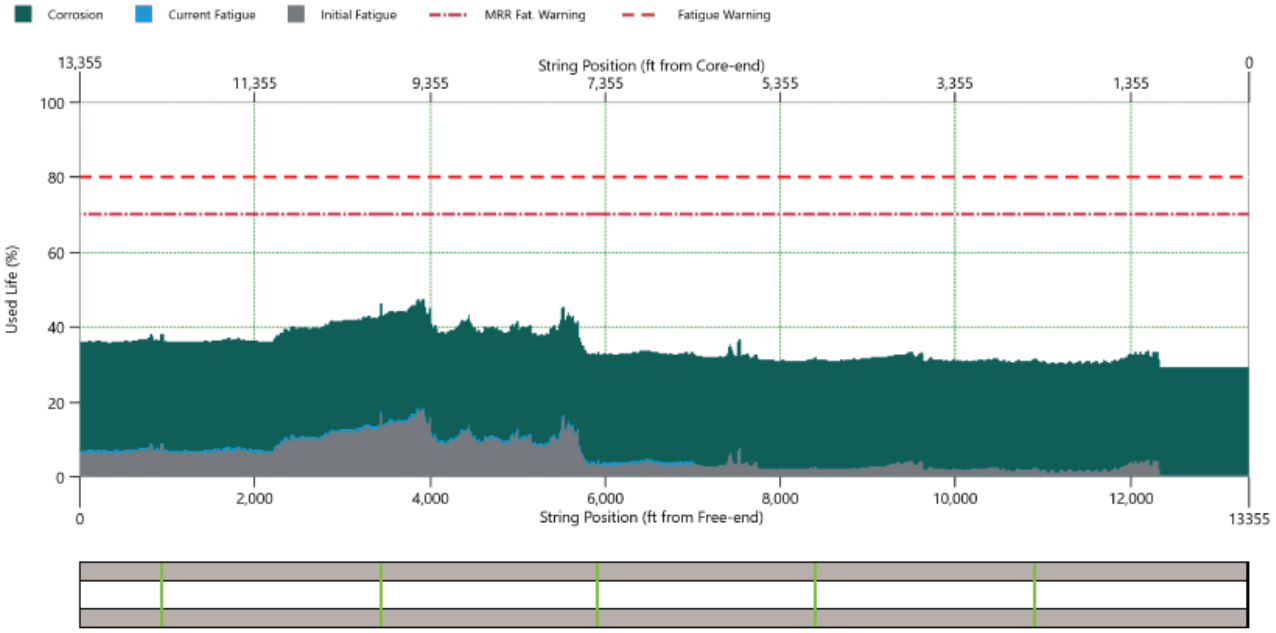
Well	Zone	Fluid Density (ppg)	Mid Perf TVD (ft)	Hydrostatic Pressure (psi)	Fracture Gradient (psi/ft)	Fracture Pressure (psi)	STP	80% MASTP
D-31	E12-13	8.80	4370	2000	0.7	3059	1059	850
D-31	E10/11	8.80	4321	1977	0.7	3025	1047	850

CT STRING INFORMATION

OD (in)	Spec	W/T (in)	ID (in)	Length (ft)
1.5	TENARIS HS-90	0.125	1.25	13,355
CT Volume: 20.3 bbls				

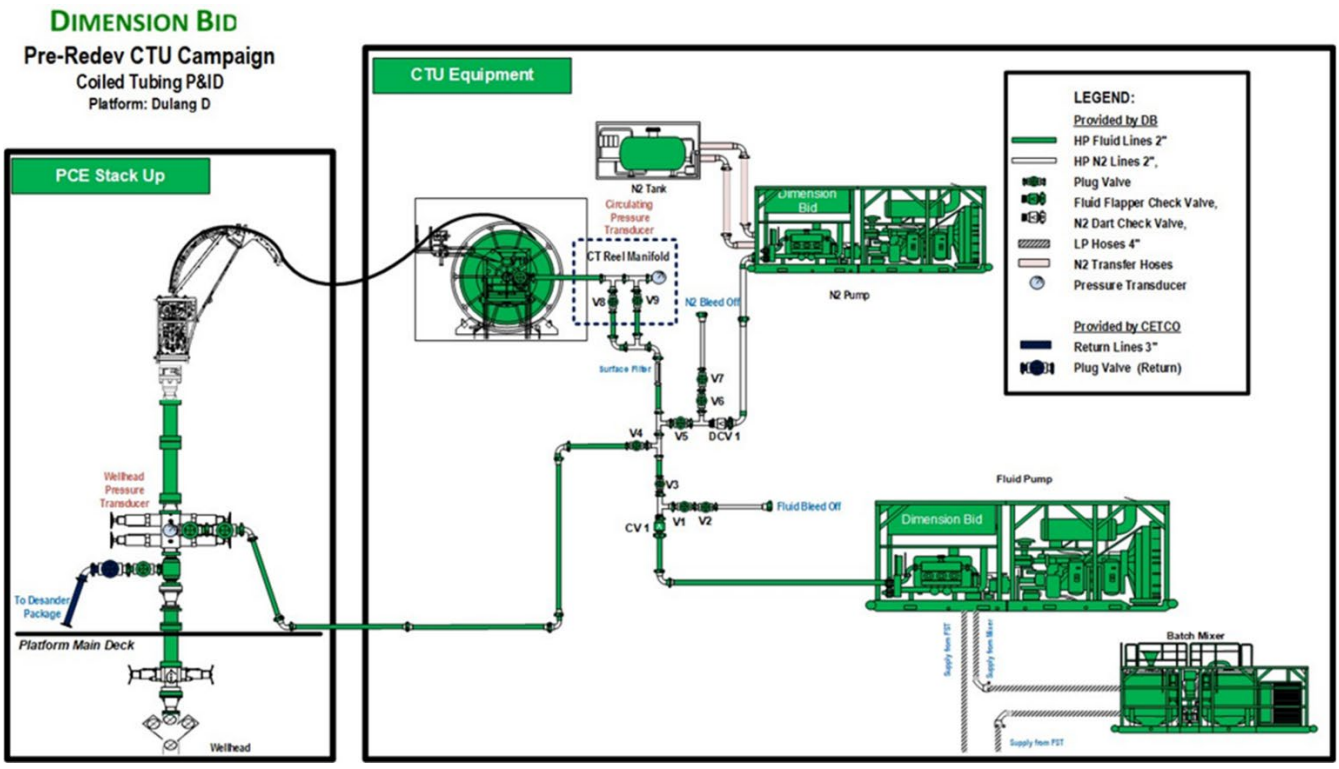
CT STRING FATIGUE

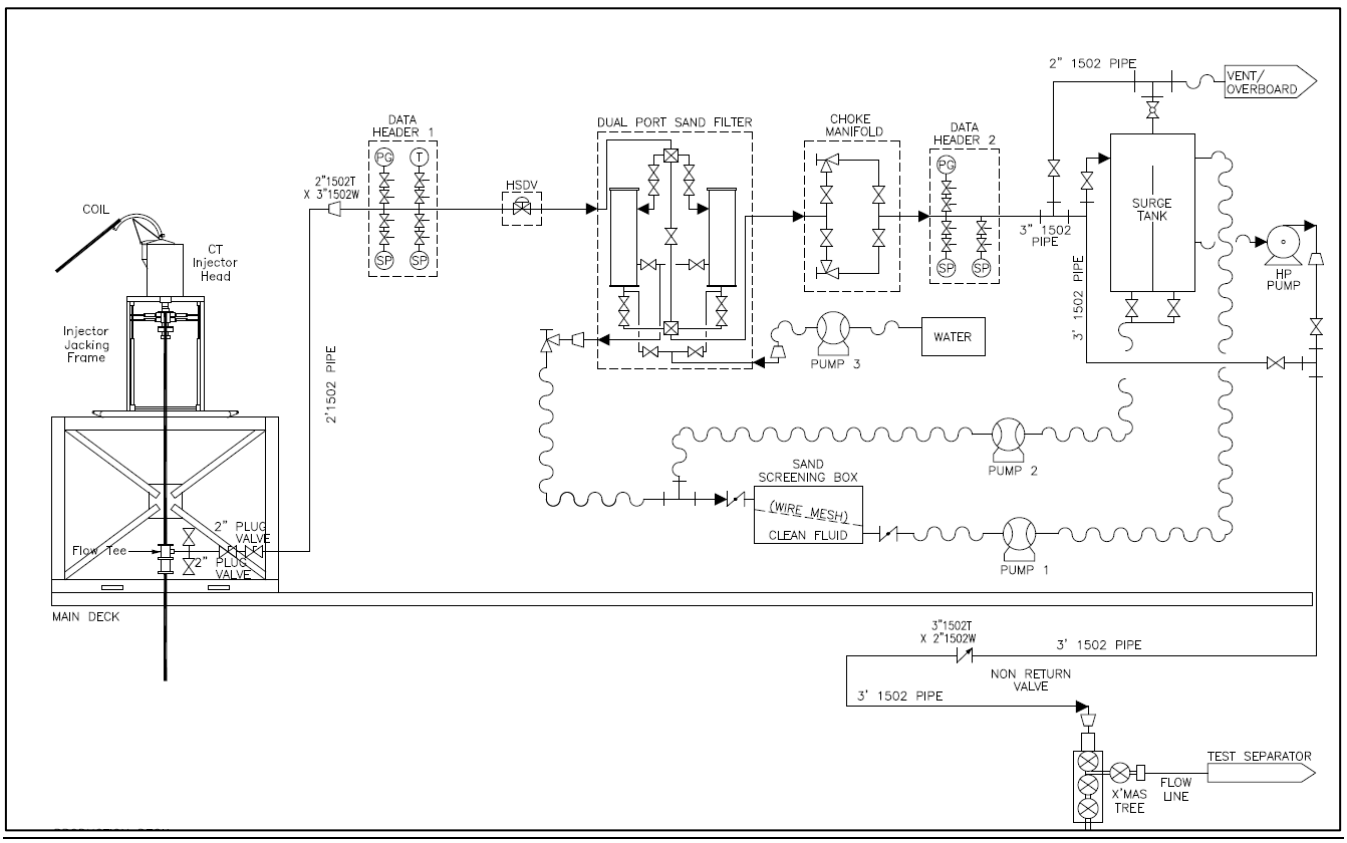
- Current **used life** for Tenaris #40146 is at **47.31%**



Run #	Date	Field Name	Well Num	Job type	Running ft	Cum. Run ft	Job Description	CT leng ft	CT cut ft	New CT leng ft	Job Fatigue %	Job Corrosion %	Max Fatigue	Cum. Corrosion %	Used String Life %
NA	27-Apr-24	Dulang-D	D-06S	Trim Coil 32FT	0	N/A	Trim Coiled 32FT	13,389	32	13,357	N/A	N/A	N/A	N/A	N/A
NA	9-May-24	Dulang-D	D-06S	Trim Coil 2FT	0	N/A	Trim CT 2ft & pickling CT.	13,357	2	13,355	N/A	N/A	N/A	N/A	N/A
24	10-May-24	Dulang-D	D-06S	Cementing	7,018	203,597	Depth Corellation & Drift Run With 2.20 FC	13,355	0	13,355	0.71	0.5	22.81	23	45.81
25	11-May-24	Dulang-D	D-06S	Cementing	6,929	210,526	To Perform Set Cement Retainer	13,355	0	13,355	0.95	0.5	23.76	23.55	47.31

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

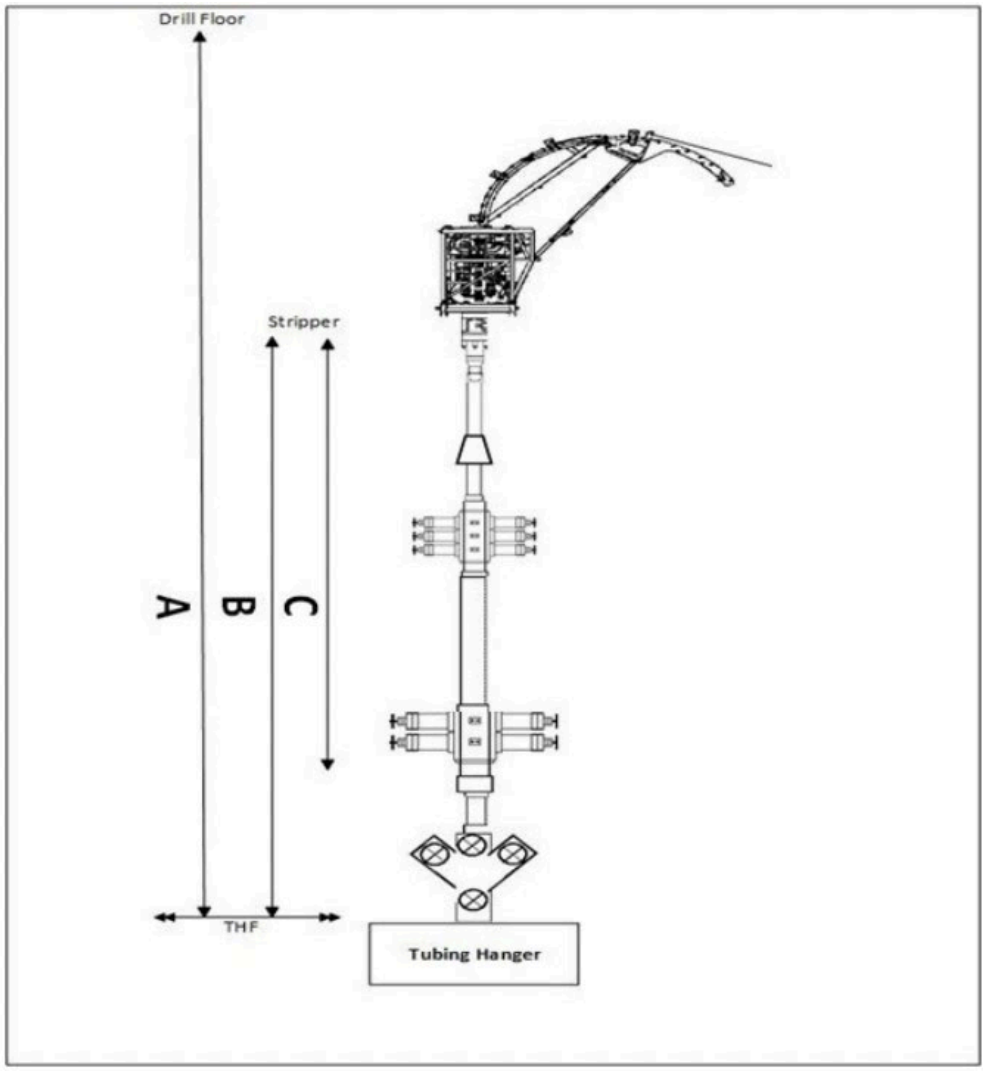
Conduct safety meeting with all personnel on location detailing the program, pressure limitations, and personnel responsibilities, well control emergency drill and safety precautions.

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 3,000 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 RUN#1: SCALE CLEANOUT FROM HUD AT 1,855 M MDTHF UNTIL 1,973 M MDTHF

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

1. Collect well fluid sample before shut in well and record pH & water cut. Record SITHP & PCP. This will be reference during flowback.

   1.1 Label the sample bottle with type of sample, name of well, date and time the sample was collected.

Sample	Volume	pH Reading	Water Cut, %
Produced Fluid	1,000 mL		

2. Rig up CT unit and surface line on Dulang-D platform:

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

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

   2.3. Rig up CT package and surface treating line.

   2.4. Rig up 2" kill line to BOP kill port.

   2.5. Rig up 2" flexible hose from pumping tee.

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

   2.7. Install the Pull and Pressure Test Sub.

   2.8. 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.

   2.9. 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.

   2.9.1. 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.

   2.9.2. **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.

   2.10. Pickle the CT String with 10 bbls of 7.5% HCl, followed by 25 bbls of IW and neutralization fluid (soda ash) to remove internal rust and ensure no foreign debris inside the CT string. If CT Pickle has been done, this will be not necessary. Please refer below 7.5% HCl mixing chemical recipe:

7.5% HCl (CT Pickle)			420	gals	10	bbls	Description
Products	Concentration		Volume				
Injection Water	794	gptg	333	gals	7.92	bbls	Base Fluid
33% HCl	202	gptg	84	gals	2.00	bbls	Raw acid
Corr 400	4	gptg	2	gals	0.01	bbls	Corrosion Inhibitor

Mixing Instruction:
1. Fill up tank with injection water
2. Add 33% HCl & Corr 400 into the tank
3. Agitate until the mixture is homogenous

3. Prepare 100bbls of Injection Water, IW as per recipe below:

Injection Water (IW)				100	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	994	gptg	4,175	gal	Base Fluid
Mixing Instruction: a) Prepare Injection Water into the mixing tank.						

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

4. 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.

5. Make up 1.69" Spincat Nozzle tool as per **BHA#1: 1.69" Spincat Nozzle BHA** in **Appendix 1**.

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

6. 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)	Pressure (psi)	Remark
0.3		
0.5		
0.7		
0.8		
0.9		
1.0		
1.1		

7. Box up to connect the riser and prepare for pressure test.
8. Pick up CT and tag BHA with the stripper.
9. CT stack up pressure test against Wellhead Crown valve. Pumping IW 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.

   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.

   9.2. For high pressure:

   Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 2,700 psi) over the 15- minutes test interval after the pressure stabilizes.

10. 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.

10.1. 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 9 and 10.

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

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

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

CV Opening Turns	LMV Opening Turns

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

13.4. Manipulate surface valve to the following position:

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

14. Start RIH BHA while pumping IW at 0.3bpm until last encountered HUD depth at 1,855 m with reference to previous Slickline HUD.

14.1. **Make 2 passes across every SPM starting from SPM#1 until SPM#6. Perform jet clean at maximum rate every SPM 10 m above & 10 m below.**

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

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

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

14.5. 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.

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

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

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

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

14.10. 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 CT reached at 1,845 m (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

16. Continue RIH at 10 ft/min until 1,855 m (previous slickline HUD). Do not slack off more than -500 lbf (downhole force).
17. Once CT at 1,855 m, spot 5 bbls of 15% HCl acid on top of Scale HUD & soak for 2 hours. Please refer pumping sequence below:

#	Start Depth (m)	End Depth (m)	Fluid at Reel Manifold	Fluid Entry Volume (bbl)	Total Fluid Pumped (bbl)	Pump Rate (bpm)	CT Speed (ft/min)	Fluid at Nozzle	Valves Config. Flow Tee	Remarks
1	1,855	1,855	15% HCl acid	5	5	0.5	-	IW	*Open Return	Start pump 5 bbls of 15% HCl acid
2	1,855	1,855	IW	15	20	0.5	-	15% HCl acid	*Open Return	15% HCl acid at tip of nozzle
3	1,855	1,855	IW	5	25	0.5	-	IW	*Close Return	5 bbls of 15% HCl acid exit nozzle

*Note: CT Volume: 20 bbls

18. Establish return by pumping at 1.1 bpm prior to penetrate by pumping 100 bbls of IW (or consider 1.5x completion Volume: 150 bbls if no return at surface).

Notes:

- If no return, please follow pumping parameter as per CIRCA: **0.8 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.

19. Continue RIH to perform cleanout at 10 ft/min while pumping nitrified IW (0.8 bpm & 300 scf/min) starting at depth 1,855 m until 1,973 m (PXN Plug) as per summary table below:

    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	IW	0.8	0.0	300	0	0	10m above HUD (1,845 m)	Establish return on surface
2	RIH to HUD and Penetrate HUD/Fill	IW	0.8	10.0	300	10	30	HUD + 30m	Monitor return & CT weight on surface
3	Circulate	D801 Gel	0.8	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	IW	0.8	10.0	300	10	10	HUD + 30m	Monitor return & CT weight on surface
5	Circulate	D801 Gel	0.8	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 PXN Plug at 1,973 m									
6	Hole Cleaning (Circulate)	D801 Gel	0.8	40	300	0	40	Dynamic CT at 1,972 m	Hole cleaning stage. 1.0x CT/Tubing Annulus Volume
7	Bottoms Up (Circulate)	IW	0.8	560	300	0	560	Dynamic CT at 1,972 m	Hole Cleaning stage. As per Circa Simulation
8	Once completed CBU and clear return is established, wiper trip to 1,630 m. Perform high jetting across every SSD for 2 passes starting from SSD#4 until SSD#1								
9	RIH back to 1,942 m while pumping at idle rate 0.3 bpm.								
10	POOH with 30ft/min while spotting 7.5% HCl acid at 0.3 bpm to perform tubing pickling from 1,942 m to surface. Close well & soak for 1 hour.								

20. 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.

    20.1. RIH and slack off CT not exceeding 500 lbf (downhole force) 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 (Soda Ash)				10	BBL	Description
Seq	Product	Concentration		Volume		
1	Injection Water	976	gptg	9.8	bbl	Base Fluid
2	Soda Ash	500	gptg	210	lbs	Neutralization Fluid

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

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

20.3. If no success during jetting HCl acid, proceed to spot another 5 bbls of 15% HCl on top of obstruction (HUD) and soak the acid for 2 hours. After completed soaking, proceed to RIH to pass through the obstruction while pumping nitrified IW. If unable to penetrate consult town for further instruction.

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

20.5. During circulation, if acid return observes on surface return line, inject soda ash using graco pump on the surface return line to neutralize the acid.

21. Once CT reach 1,973 m (PXN Plug), circulate 40 bbls of Gel and perform bottoms up with Nitrified IW (0.8 bpm & 300 scf/min) for 8 hours at depth 1,972 m as per CIRCA Simulation. Flag #1 CT at surface at depth 1,973 m (PXN Plug).

Note: Dynamic the CT at depth for every 30 minutes. Always monitor weight parameter.

Flag Number	Colour
Flag#1	

22. Wiper trip to depth to 1,630 m while pumping Nitrified IW (0.8 bpm & 300 scf/min) at 10 ft/min.

22.1. **Make 2 passes across every SSD starting from SSD#4 until SSD#1. Perform jet clean at maximum rate at every SSD 10 m above & 10 m below.**

23. RIH back to 1,942 m (SSD#4) while pumping at idle rate 0.3 bpm.

24. POOH CT to surface at **30 ft/min** while spotting 63 bbls of 7.5% HCl acid (tubing pickling) at 0.3 bpm.

7.5% HCl				**2730**	**gals**	**65**	**bbls**	**Description**
Seq	**Product**	**Concentration**		**Volume**				
1	**Fresh Water**	739	gptg	2,017	gals	48.04	bbls	Base Fluid
2	ACM CORR 400	4	gptg	11	gals	0.26	bbls	Acid Corrosion Inhibitor
3	MESB NE 500	4	gptg	11	gals	0.26	bbls	Non-Emulsifier
4	ACM Surf 210	3	gptg	8	gals	0.20	bbls	Surfactant
5	NH4Cl Powder	417	pptg	1138	lbs			Clay Stabilizer
6	ACM Iron 300	10	pptg	27	lbs			Iron Sequestering
7	ACM Iron 200	15	gptg	41	gals	0.98	bbls	Iron Control
8	33% HCl	202	gptg	551	gals	13.13	bbls	Raw Acid
Mixing Instruction: 1. Fill up tank with fresh water 2. Add additives as per above sequence 3. Agitate until mixture is homogeneous								

25. Once CT at surface, close well & soak for 1 hour.

26. Flowback the well assisted by gas lift. Ensure graco pump is already rigged up at tapping point downstream of wing valve and soda ash is mixed. Refer to table below for soda ash recipe:

Neutralization Fluid (Soda Ash)				**10**	**BBL**	**Description**
Seq	**Product**	**Concentration**		**Volume**		
1	Injection Water	976	gptg	9.8	bbl	Base Fluid
2	Soda Ash	500	gptg	210	lbs	Neutralization Fluid
Mixing Instruction: 1. Prepare injection water into mixing tank 2. Mix soda ash into tank and agitate until the mixture is homogenous.						

27. Monitor pH of return fluids constantly, every 5 minutes. Stop injecting soda ash when pH reading is neutral.

    27.1. Record the following parameters for every 5 minutes during monitor well flowback. Include the following table in daily report.

Monitoring Checklist

Field/Platform/Well :
Engineer :

No.	Date	Time	Choke Size	pH.	% Water Cut	Bbl Counter	FLT	FTHP	Remark
1									
2									
3									
4									
5									
6									
7									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

27.2. Take 500 ml return sample after fully recovered all acid pumped.

28. Handover well to Slickline for TCC & shift close SSD #2 (E6) & SSD #3 (E10-11).

BULLHEADING#1 OPERATION – INJECTIVITY TEST ON ZONE E12-13

29. Line up 2" treating line from single pump to slickline pumping tee.
30. Perform pressure test for the treating line against crown valve up to 500 psi and holds for 5 minutes and increase to 3,000 psi and holds for 10 minutes.
31. Once completed, bleed off pressure through the bleed off line by fully opening the master plug valve (2x1 plug valve) then slowly open the control valve (2x1 plug valve). Ensure pressure is bled to zero.
32. Prior start pumping activity, complete the following:

    32.1. Record SITHP and PCP. Include in daily report.

SITHP	PCP

    32.2. Bleed off tubing and casing pressure to minimum as possible or at least 700 psi.

33. Prepare 100 bbls of Treated Fresh Water, TFW as per recipe below:

Treated Fresh Water			**4,200**	**gals**	**100**	**bbls**	**Description**
Products	**Concentration**		**Volume**				
Fresh Water	959	gptg	4,028	gals	95.90	bbls	Base Fluid
MESB NE-Surf 200	2	gptg	8	gals	0.20	bbls	Non-Emulsifier Surfactant
Ammonium Chloride	417	pptg	1,751	lbs			Clay Stabilizer
ACM Oxyfree 100	2	gptg	8	gals	0.20	bbls	Oxygen Scavenger
ACM H2SClear 200	2	gptg	8	gals	0.20	bbls	CO2 & H2S Corrosion Inhibitor
ACM Bact 200	2	gptg	8	gals	0.20	bbls	Microbiocide

Mixing Instruction:
4. Fill up tank with fresh water
5. Add additives as per above sequence
6. Agitate until the mixture is homogenous

34. Open plug valve at the surface line that connects to pump-in tee and start pumping according to the pumping table in **Step 35**.

    34.1. **Do not exceed maximum allowable surface treating pressure 850 psi.**

    34.2. While filling up tubing, record THP and PCP as per table below. Include the following table in daily report.

Time (min)	Pump Pressure (psi)	Volume (bbl)	THP (psi)	PCP (psi)	Remark

35. Proceed with pump TFW to fill up completion volume (**65 bbls**) prior injectivity test as per below table:

Pumping Schedule to Fill up Completion Volume for Injectivity Test						
Stage	**Description**	**Fluid**	**Vol (bbl)**	**Pump Rates (bpm)**	**Remarks**	**MASTP (psi)**
1	**Fill-up Completion Volume**	**TFW**	65 bbls or till return is	0.5 – 1.0	65 bbls is calculated based on 1.0x	850

			observed on surface.		completion volume (Tubing & Wellbore)	

36. After complete pumping as per above pumping schedule, do not stop pumping and continue pumping at idle rate.

    36.1. Sustain each pumping rate for **5 minutes** after pressure stabilises. For last achievable rate, prolong the monitoring for 15 minutes.

    36.2. DO NOT exceed MASTP 850 psi.

    36.3. **Proposed injection rate for main treatment is 0.5 – 1.0 bpm.**

    36.4. Begin injectivity test as per table below:

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbls)	THP (psi)	PCP (psi)
0.30					
0.50					
0.70					
1.00					
1.30					

37. Fill up table and include in daily report. Report the results of injectivity test to WSS and EIC at town.

BULLHEADING#2 OPERATION – ACID WASH ON ZONE E12-13 (MAIN TREATMENT)

38. Proceed with main treatment after receiving approval from town.

39. Prepare treatment fluid as per below:

Pre-Flush Solvent				840	gals	20	bbls	Description
Seq	Product	Concentration		Volume				
1	Fresh Water	863	gptg	725	gals	17.3	bbls	Base Fluid
2	MESB NE-Surf 200	4	gptg	3	gals	0.1	bbls	Non-Emulsifier Surfactant
3	NH4Cl Powder	417	pptg	350	lbs			Clay Stabilizer
4	MESB MS 300	100	gptg	84	gals	2.0	bbls	Mutual Solvent
Mixing Instruction: 1. Fill up tank with fresh water 2. Add additives as per above sequence 3. Agitate until mixture is homogeneous								

15% HCl				2730	gals	65	bbls	Description
Seq	Product	Concentration		Volume				
1	Fresh Water	419	gptg	1,144	gals	27.24	bbls	Base Fluid
2	ACM CORR 400	4	gptg	11	gals	0.26	bbls	Acid Corrosion Inhibitor
3	MESB NE 500	4	gptg	11	gals	0.26	bbls	Non-Emulsifier
4	ACM Surf 210	3	gptg	8	gals	0.20	bbls	Surfactant
5	Ammonium Chloride	417	pptg	1,138	lbs			Clay Stabilizer
6	ACM Iron 300	25	pptg	68	lbs			Iron Sequestering
7	ACM Iron 200	15	gptg	41	gals	0.98	bbls	Iron Control
8	33% HCl	419	gptg	1,144	gals	27.24	bbls	Raw Acid
9	MESB MS 300	100	gptg	273	gals	6.50	bbls	Mutual Solvent
Mixing Instruction: 1. Fill up tank with fresh water 2. Add additives as per above sequence 3. Agitate until mixture is homogeneous								

Injection Water (IW)				100	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	994	gptg	4,175	gal	Base Fluid
Mixing Instruction: a) Prepare Injection Water into the mixing tank.						

40. Manipulate Surface valve to the following position prior pumping activity;

Valve	Position
Pump-In Tee Valve (Slickline)	OPEN
Swab Valve	OPEN
Lower Master Valve	OPEN
Wing Valve	CLOSE

41. Prior start pumping activity, complete the following:

    41.1. Record SITHP and PCP. Include in daily report.

SITHP	PCP

42. Bleed off tubing and casing pressure to minimum as possible or at least 700 psi.

43. Commence pumping as per below pumping schedule:

Pumping Schedule for Main Treatment						
Stage	**Description**	**Fluid**	**Vol (bbl)**	**Pump Rates (bpm)**	**Remarks**	**MASTP (psi)**
1	**Pre-flush (1 ft penetration)**	Solvent	**18**	0.5-1.0	Remove organic deposit	850
2	**Main Acid (2ft penetration + wellbore)**	15% HCl Acid	**63**	0.5-1.0	To dissolve calcite scale & soak across interval	850
3	**Displacement Fluid**	IW	**65**	0.5-1.0	To displace treatment fluid into formation	850
4	**Surface Line Displacement**	IW	*	0.5-1.0	To displace surface line volume	850
Shut in well and soak for 4 hours						
Once complete, open up well & flowback to recover 219 bbls (1.5x total pumped fluid)						
• **Max WHP is 850 psi throughout pumping sequence.** • **Maintain pumping rate throughout the pumping stage. To compare injectivity index pre and post treatment.** • ***: Depend on surface line volume**						

44. Record the following parameters while pumping. Include the following table in daily report.

Time (min)	Pump Pressure (psi)	Volume (bbl)	THP (psi)	CHP (psi)	Remark

45. Ensure graco pump is already rigged up at tapping point downstream of wing valve and soda ash is mixed. Refer to table below for soda ash recipe:

Neutralization Fluid (Soda Ash)				**10**	**BBL**	**Description**
Seq	**Product**	**Concentration**		**Volume**		
1	Injection Water	976	gptg	9.8	bbl	Base Fluid
2	Soda Ash	500	gptg	210	lbs	Neutralization Fluid
Mixing Instruction: 1. Prepare injection water into mixing tank 2. Mix soda ash into tank and agitate until the mixture is homogenous.						

Note: The above recipe is for 10 bbls of Soda Ash. Please prepare another batch if needed.

46. Start injecting soda ash once observed pH of return fluid is acid.

46.1. In the event of unable to flowback the fluid, continue with over-flush treatment using treated injection water (Volume: 400 bbls of TIW inclusive of tubing, wellbore and 5ft penetration)

47. Monitor pH of return fluids constantly, every 15 minutes. Stop injecting soda ash when pH reading is neutral.

48. Record the following parameters during monitor well flowback. Include the following table in daily report.

Monitoring Checklist

Field/Platform/Well :
Engineer :

No.	Date	Time	Choke Size	pH.	% Water Cut	Bbl Counter	FLT	FTHP	Remark
1									
2									
3									
4									
5									
6									
7									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

49. Once flowback activity is completed (**219 bbls** fluid recover & pH back to initial), inform WSS and handover well to production.

49.1. Take 500 ml return sample after recovering 216 bbls of liquid on surface.

49.2. Label the sample as “Acidizing flowback” along with time and date of sampling.

50. Handover well to Slickline to shift close SSD#4 (E12-13) & open SSD#3 (E10-11)

BULLHEADING#3 OPERATION – INJECTIVITY TEST ON ZONE E10-11

51. Line up 2" treating line from single pump to slickline pumping tee.
52. Perform pressure test for the treating line against crown valve up to 500 psi and holds for 5 minutes and increase to 3,000 psi and holds for 10 minutes.
53. Once completed, bleed off pressure through the bleed off line by fully opening the master plug valve (2x1 plug valve) then slowly open the control valve (2x1 plug valve). Ensure pressure is bled to zero.
54. Prior start pumping activity, complete the following:

    54.1. Record SITHP and PCP. Include in daily report.

SITHP	PCP

    54.2. Bleed off tubing and casing pressure to minimum as possible or at least 700 psi.

55. Prepare 100 bbls of Treated Fresh Water, TFW as per recipe below:

Treated Fresh Water			**4,200**	**gals**	**100**	**bbls**	**Description**
Products	**Concentration**		**Volume**				
Fresh Water	959	gptg	4,028	gals	95.90	bbls	Base Fluid
MESB NE-Surf 200	2	gptg	8	gals	0.20	bbls	Non-Emulsifier Surfactant
Ammonium Chloride	417	pptg	1,751	lbs			Clay Stabilizer
ACM Oxyfree 100	2	gptg	8	gals	0.20	bbls	Oxygen Scavenger
ACM H2SClear 200	2	gptg	8	gals	0.20	bbls	CO2 & H2S Corrosion Inhibitor
ACM Bact 200	2	gptg	8	gals	0.20	bbls	Microbiocide

Mixing Instruction:

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

56. Open plug valve at the surface line that connects to pump-in tee and start pumping according to the pumping table in **Step 57**.

    56.1. **Do not exceed maximum allowable surface treating pressure 850 psi.**

    56.2. While filling up tubing, record THP and PCP as per table below. Include the following table in daily report.

Time (min)	Pump Pressure (psi)	Volume (bbl)	THP (psi)	PCP (psi)	Remark

57. Proceed with pump TFW to fill up completion volume (**65 bbls**) prior injectivity test as per below table:

Pumping Schedule to Fill up Completion Volume for Injectivity Test						
Stage	**Description**	**Fluid**	**Vol (bbl)**	**Pump Rates (bpm)**	**Remarks**	**MASTP (psi)**
1	**Fill-up Completion Volume**	**TFW**	65 bbls or till return is	0.5 – 1.0	65 bbls is calculated based on 1.0x	850

			observed on surface.		completion volume (Tubing & Wellbore)	

58. After complete pumping as per above pumping schedule, do not stop pumping and continue pumping at idle rate.

    58.1. Sustain each pumping rate for **5 minutes** after pressure stabilises. For last achievable rate, prolong the monitoring for 15 minutes.

    58.2. DO NOT exceed MASTP 850 psi.

    58.3. **Proposed injection rate for main treatment is 0.5 – 1.0 bpm.**

    58.4. Begin injectivity test as per table below:

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbls)	THP (psi)	PCP (psi)
0.30					
0.50					
0.70					
1.00					
1.30					

59. Fill up table and include in daily report. Report the results of injectivity test to WSS and EIC at town.

BULLHEADING#4 OPERATION – ACID WASH ON ZONE E10-11 (MAIN TREATMENT)

60. Proceed with main treatment after receiving approval from town.

61. Prepare treatment fluid as per below:

Pre-Flush Solvent				420	gals	10	bbls	Description
Seq	Product	Concentration		Volume				
1	Fresh Water	863	gptg	362	gals	8.6	bbls	Base Fluid
2	MESB NE-Surf 200	4	gptg	2	gals	0.1	bbls	Non-Emulsifier Surfactant
3	NH4Cl Powder	417	pptg	175	lbs			Clay Stabilizer
4	MESB MS 300	100	gptg	42	gals	1.0	bbls	Mutual Solvent
Mixing Instruction: 1. Fill up tank with fresh water 2. Add additives as per above sequence 3. Agitate until mixture is homogeneous								

15% HCl				1260	gals	30	bbls	Description
Seq	Product	Concentration		Volume				
1	Fresh Water	419	gptg	528	gals	12.57	bbls	Base Fluid
2	ACM CORR 400	4	gptg	5	gals	0.12	bbls	Acid Corrosion Inhibitor
3	MESB NE 500	4	gptg	5	gals	0.12	bbls	Non-Emulsifier
4	ACM Surf 210	3	gptg	4	gals	0.09	bbls	Surfactant
5	Ammonium Chloride	417	pptg	525	lbs			Clay Stabilizer
6	ACM Iron 300	25	pptg	32	lbs			Iron Sequestering
7	ACM Iron 200	15	gptg	19	gals	0.45	bbls	Iron Control
8	33% HCl	419	gptg	528	gals	12.57	bbls	Raw Acid
9	MESB MS 300	100	gptg	126	gals	3.00	bbls	Mutual Solvent
Mixing Instruction: 1. Fill up tank with fresh water 2. Add additives as per above sequence 3. Agitate until mixture is homogeneous								

Injection Water (IW)				100	BBL	Description
Seq.	Product	Concentration		Volume		
1	Injection Water	994	gptg	4,175	gal	Base Fluid
Mixing Instruction: a) Prepare Injection Water into the mixing tank.						

62. Manipulate Surface valve to the following position prior pumping activity;

Valve	Position
Pump-In Tee Valve (Slickline)	OPEN
Swab Valve	OPEN
Lower Master Valve	OPEN
Wing Valve	CLOSE

63. Prior start pumping activity, complete the following:

    63.1. Record SITHP and PCP. Include in daily report.

SITHP	PCP

64. Bleed off tubing and casing pressure to minimum as possible or at least 700 psi.

65. Commence pumping as per below pumping schedule:

Pumping Schedule for Main Treatment						
Stage	**Description**	**Fluid**	**Vol (bbl)**	**Pump Rates (bpm)**	**Remarks**	**MASTP (psi)**
1	**Pre-flush (1 ft penetration)**	Solvent	**8**	0.5-1.0	Remove organic deposit	850
2	**Main Acid (2ft penetration+ wellbore)**	15% HCl Acid	**29**	0.5-1.0	To dissolve calcite scale & soak across interval	850
3	**Displacement Fluid**	IW	**62**	0.5-1.0	To displace treatment fluid into formation	850
4	**Surface Line Displacement**	IW	*	0.5-1.0	To displace surface line volume	850
Shut in well and soak for 4 hours						
Once complete, open up well & flowback to recover 150 bbls (1.5x total pumped fluid)						
• **Max WHP is 850 psi throughout pumping sequence.** • **Maintain pumping rate throughout the pumping stage. To compare injectivity index pre and post treatment.** • ***: Depend on surface line volume**						

66. Record the following parameters while pumping. Include the following table in daily report.

Time (min)	Pump Pressure (psi)	Volume (bbl)	THP (psi)	CHP (psi)	Remark

67. Ensure graco pump is already rigged up at tapping point downstream of wing valve and soda ash is mixed. Refer to table below for soda ash recipe:

Neutralization Fluid (Soda Ash)				**10**	**BBL**	**Description**
Seq	**Product**	**Concentration**		**Volume**		
1	Injection Water	976	gptg	9.8	bbl	Base Fluid
2	Soda Ash	500	gptg	210	lbs	Neutralization Fluid
Mixing Instruction: 1. Prepare injection water into mixing tank 2. Mix soda ash into tank and agitate until the mixture is homogenous.						

Note: The above recipe is for 10 bbls of Soda Ash. Please prepare another batch if needed.

68. Start injecting soda ash once observed pH of return fluid is acid.

68.1. In the event of unable to flowback the fluid, continue with over-flush treatment using treated injection water (Volume: 217 bbls of TIW inclusive of tubing, wellbore and 5ft penetration)

69. Monitor pH of return fluids constantly, every 15 minutes. Stop injecting soda ash when pH reading is neutral.

70. Record the following parameters during monitor well flowback. Include the following table in daily report.

Monitoring Checklist

Field/Platform/Well :
Engineer :

No.	Date	Time	Choke Size	pH.	% Water Cut	Bbl Counter	FLT	FTHP	Remark
1									
2									
3									
4									
5									
6									
7									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

71. Once flowback activity is completed (**150 bbls** fluid recover & pH back to initial), inform WSS and handover well to production.

71.1. Take 500 ml return sample after recovering 150 bbls of liquid on surface.

71.2. Label the sample as “Acidizing flowback” along with time and date of sampling.

APPENDIX I – BHA SCHEMATIC

BHA#1: 1.69" SPINCAT NOZZLE BHA

DIMENSION BID

BHA DIAGRAM #1 - 1-11/16" SpinCAT Nozzle BHA

Client	Petronas Carigali	Well	D-31
Field	Dulang D	Min Restriction	2.25"
Job Type	Sand Cleanout	BHP	
Job No.		BHT	217 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**Internal Dimple Connector**	1.5" CT	1.0" AMMT PIN		1.690	0.3	0.3
	1-11/16" MHA Disconnect drop ball 5/8" Shear pressure 5,456 psi Circulating drop ball 1/2" Shear pressure 2,520 psi Burst Disc 5000 psi	1.0" AMMT BOX	1.0" AMMT PIN		1.690	2.3	2.6
	1-11/16" 5 FT Straight Bar	1.0" AMMT BOX	1.0" AMMT PIN		1.690	5.0	7.6
	1-11/16" Downhole Filter 100 Micron Size	1.0" AMMT BOX	1.0" AMMT PIN		1.690	3.2	10.8
	1-11/16" SpinCAT Nozzle 5k psi rated Up to 390 F	1.0" AMMT BOX			1.690	1.0	11.8

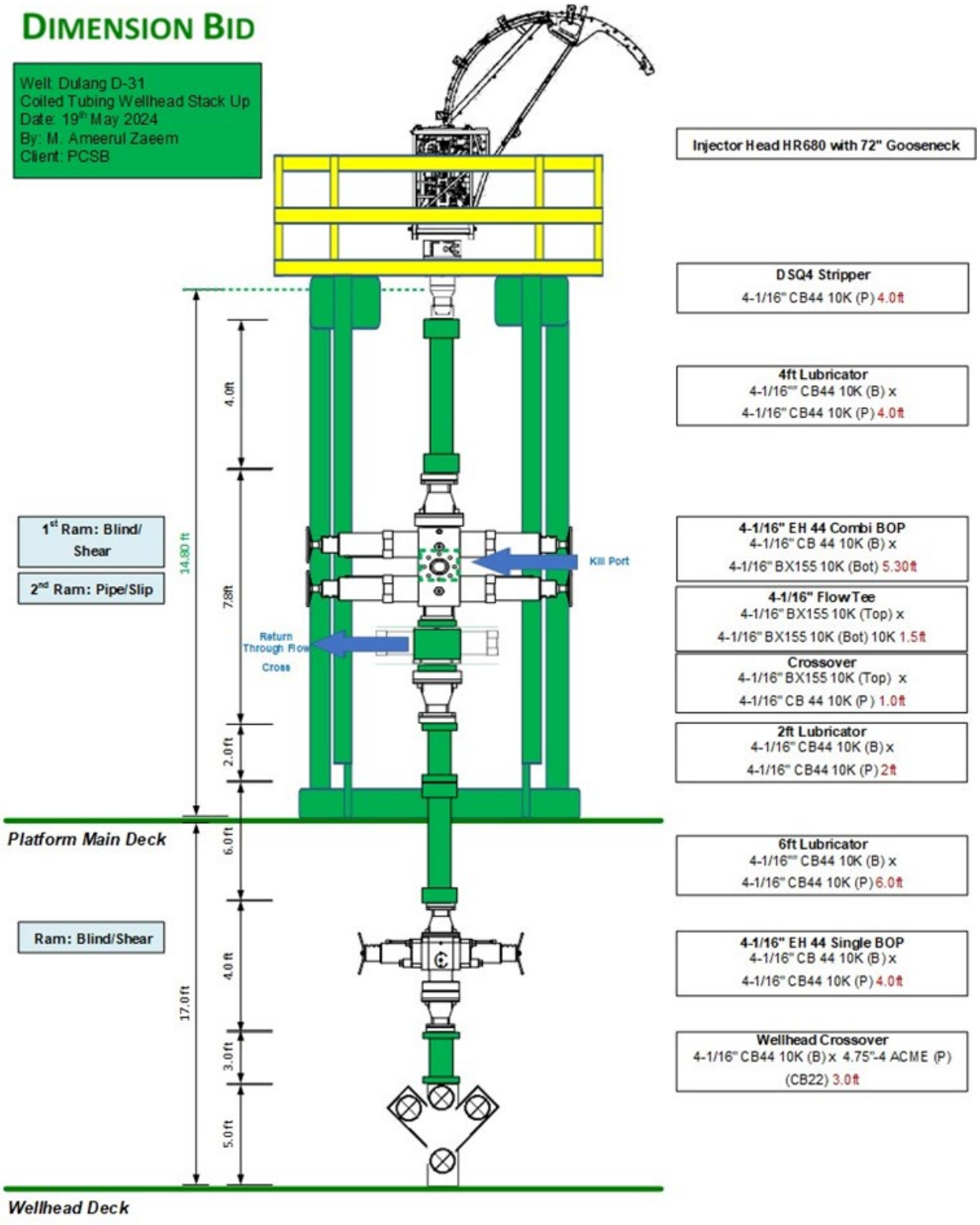
BHA LENGTH	11.80
MAXIMUM OD	1.69
MINIMUM ID	0.50

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

ADDITIONAL INFORMATION:

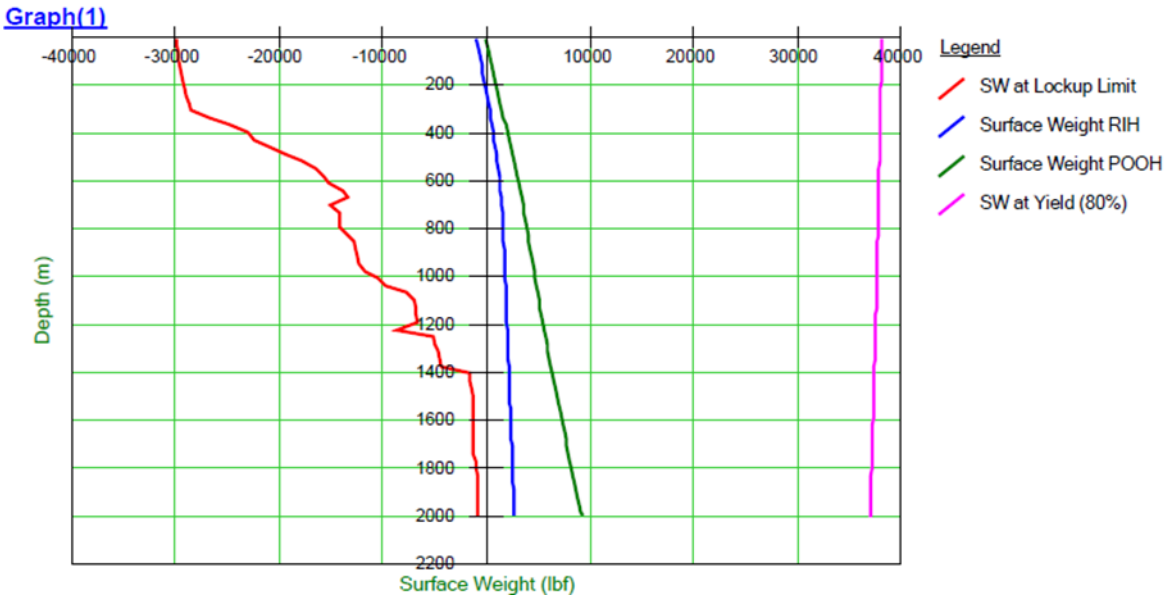
Ensure to measure length and OD of each BHA tool before makeup.

APPENDIX II – CT STACK UP

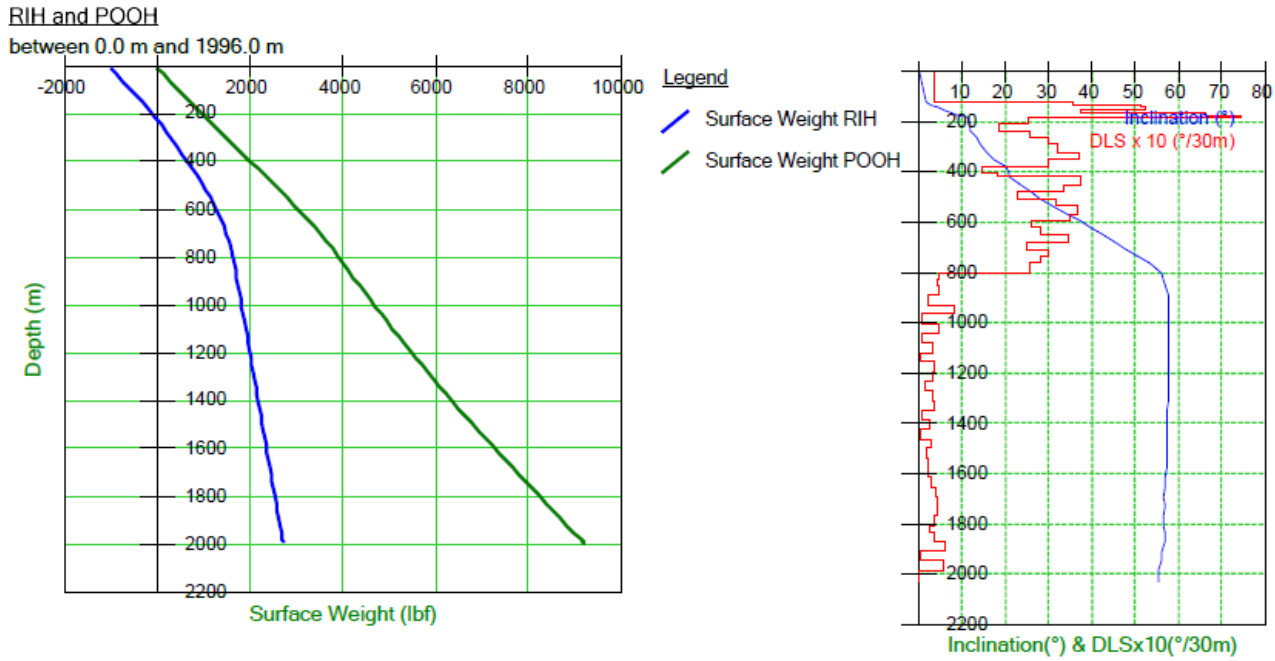


APPENDIX III – ORPHEUS SIMULATIONS

TUBING FORCE ANALYSIS AT 1,996 M MDDF

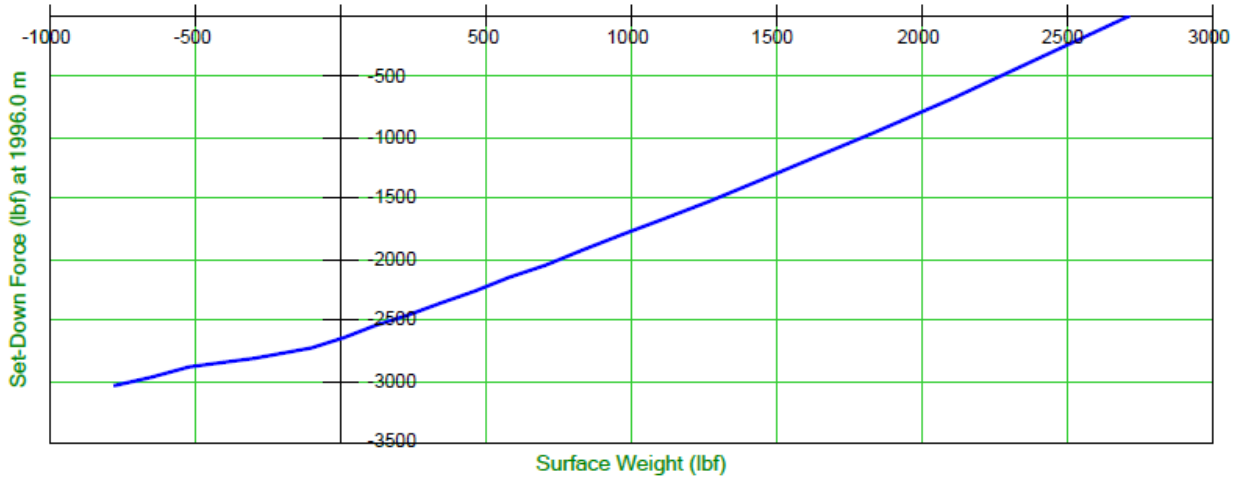


RIH & POOH WEIGHT



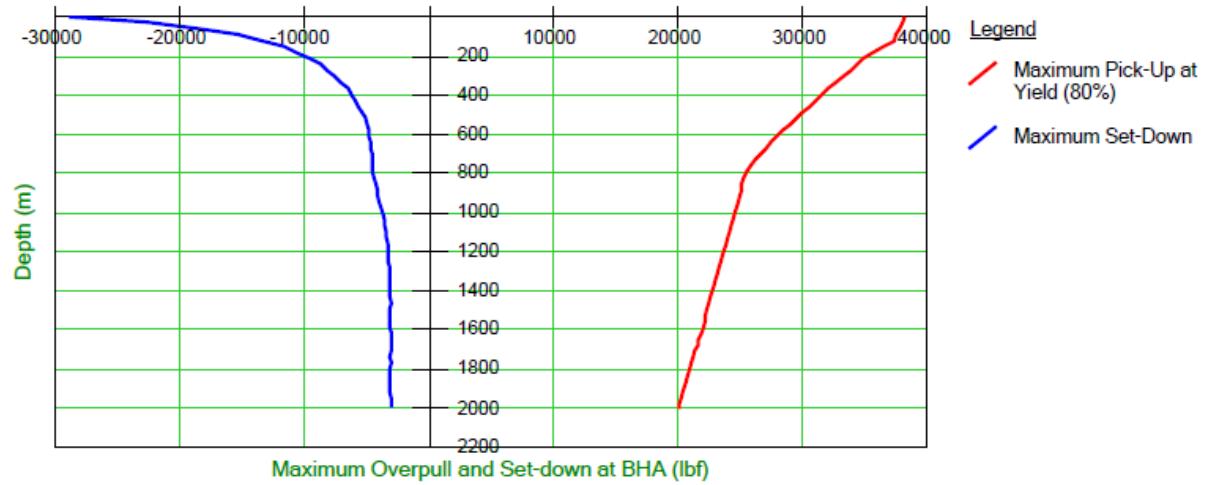
MAXIMUM STRING SET DOWN LIMIT

MD3 The available set-down force at 1996.0 m is -3040 lbf at the end of the string.
The weight indicator reading will be -779 lbf on surface.
The minimum available set-down force is -3026 lbf at 1645.9 m.



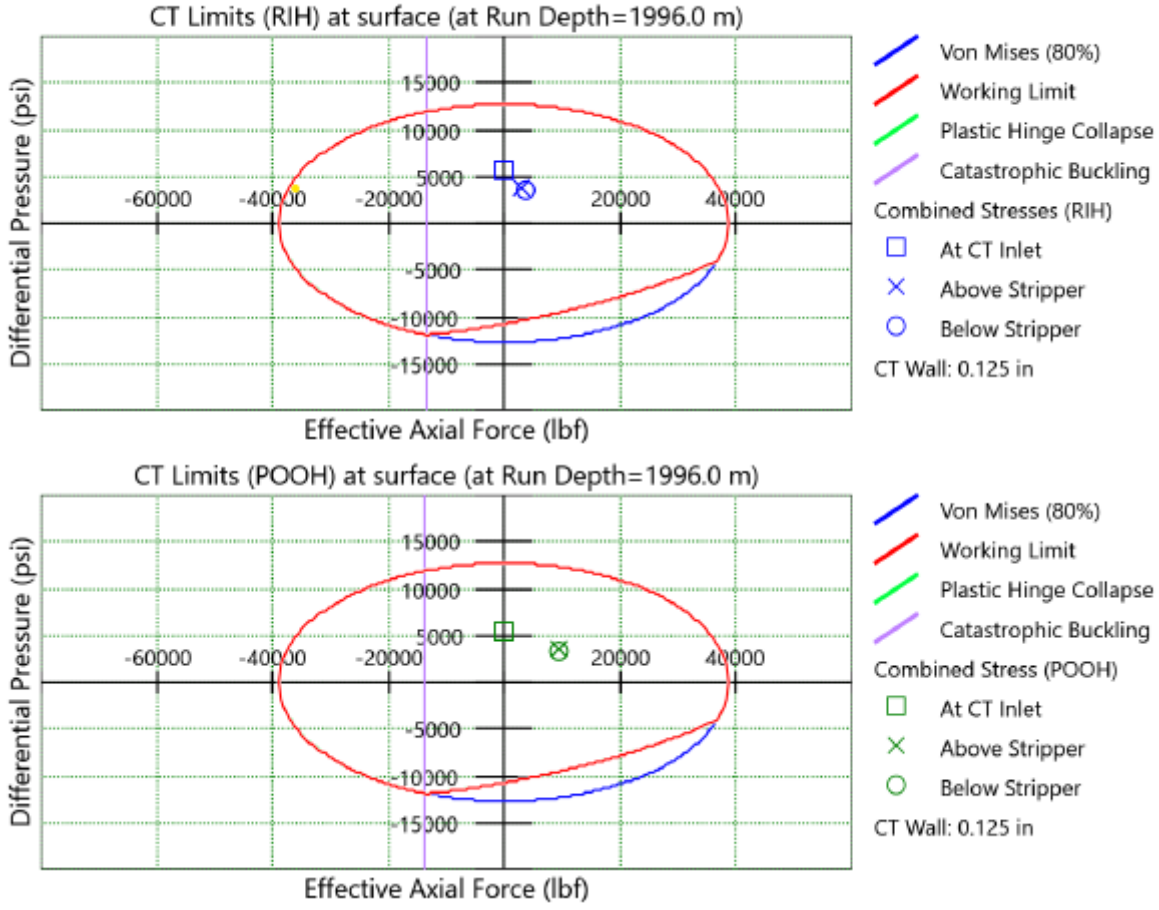
MAXIMUM STRING PICK UP LIMIT

MD1 The available pick-up at 1996.0 m based on 80% of yield strength is 20020 lbf.
The weight indicator reading will then be 37017 lbf.



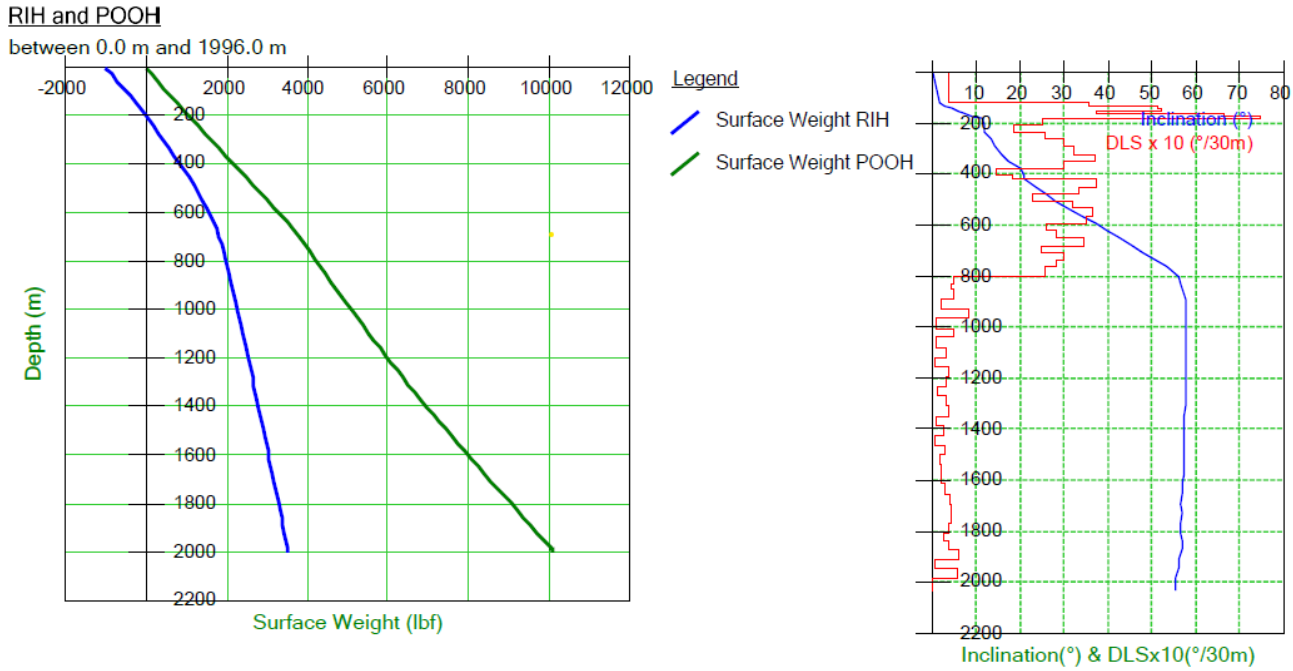
STRING LIMIT

CT Limits

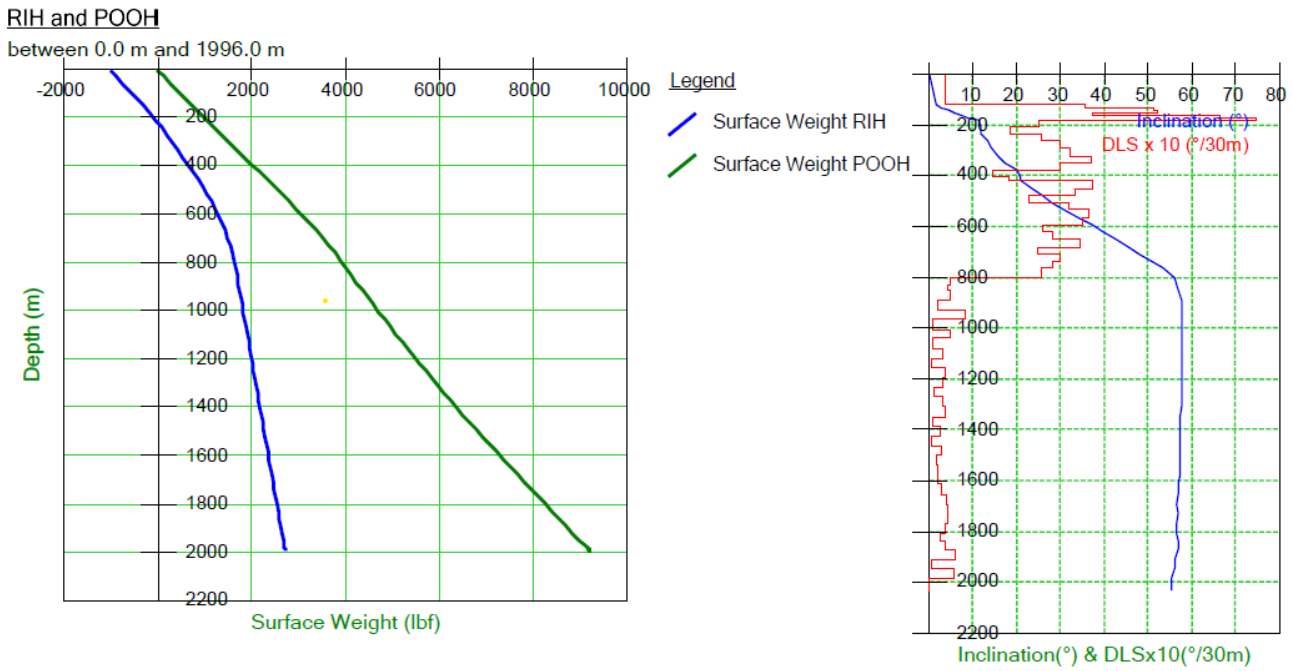


SENSITIVY ANALYSIS TFA

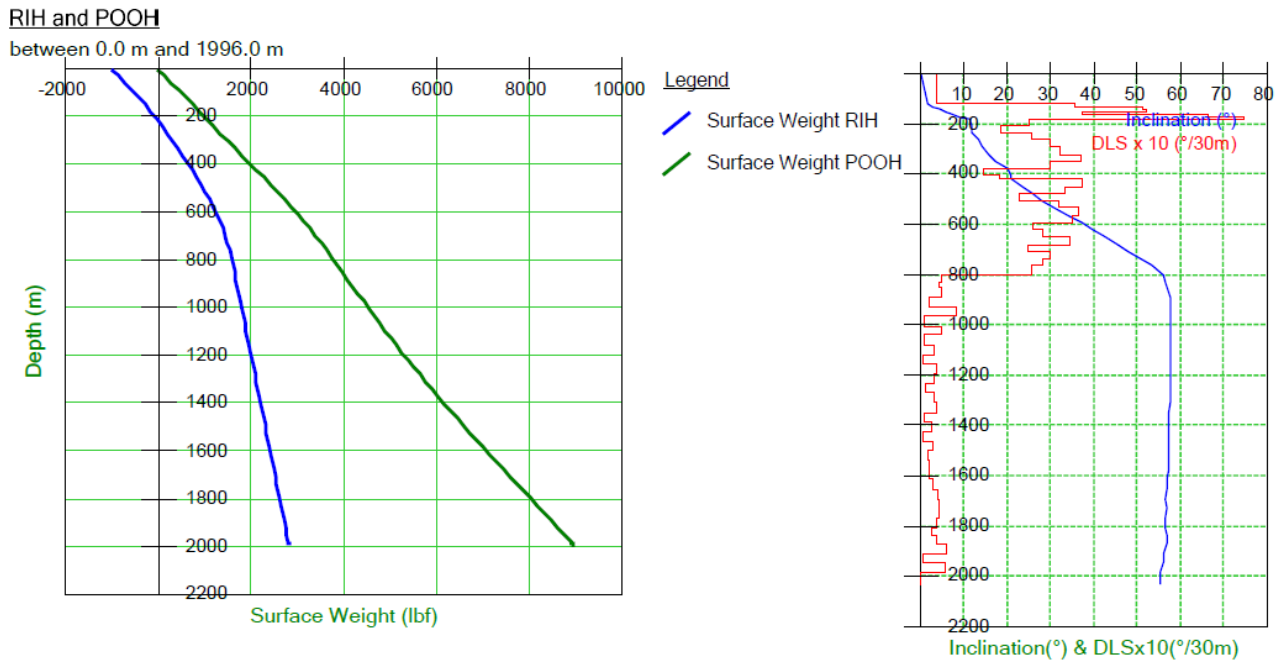
Idle Rate (0.3 bpm)



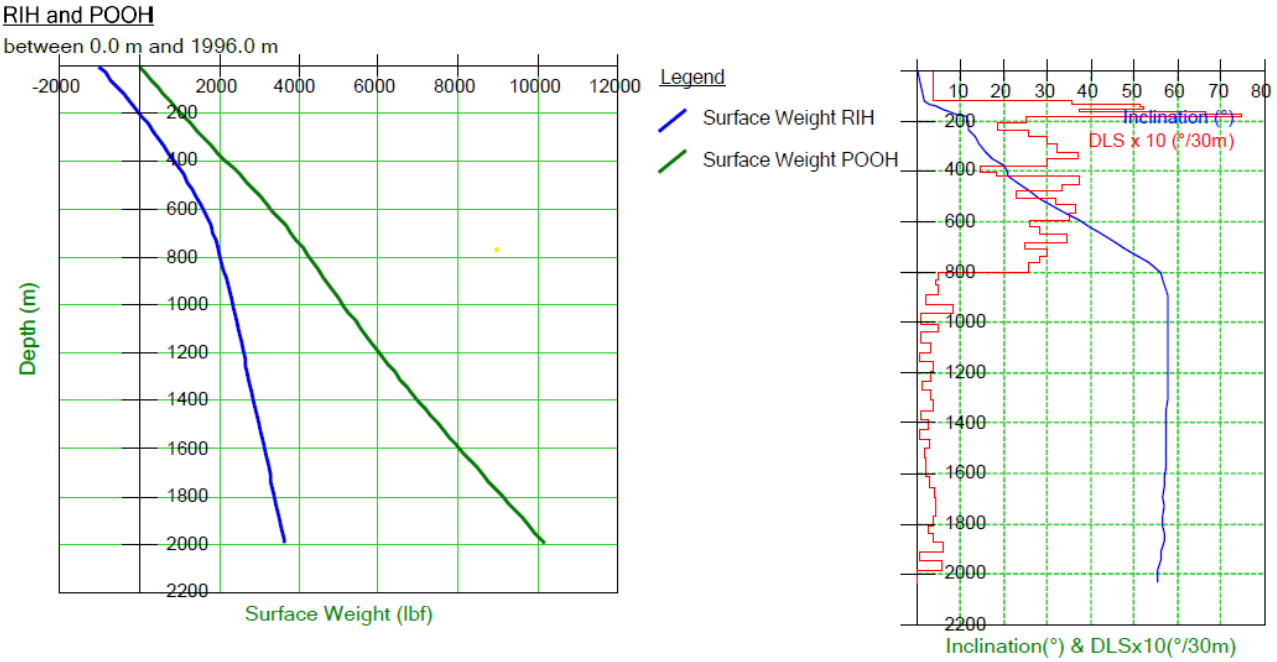
High Rate (1.1 bpm)



Nitrified (0.8 bpm 300 scf)



Without pumping (0 bpm 0 scf)



SENSITIVY ANALYSIS FRICTION FACTOR

TFA Sensitivity Analysis with various Friction Factor – 1.1BPM

Friction Factor	Depth (m)	Lock-up limit (lbf)	RIH Weight (lbf)	POOH Weight (lbf)	Max Pulling Weight at 80% Yield Limit
0.2	500	-26,655	1,028	2,440	37,956
	1,000	-11,965	2,095	4,527	37,700
	1,500	-7,505	2,732	6,386	37,374
	1,973	-4,299	3,364	8,465	37,043
0.3	500	-19,356	957	2,531	37,966
	1,000	-10,488	1,823	4,901	37,692
	1,500	-1,371	2,261	7,207	37,387
	1,973	-779	2,700	9,871	37,052
0.7	500	-12,886	703	2,940	37,960
	1,000	-12,557	734	6,756	37,699
	1,500	-12,380	162	12,172	37,392
	1,973	-11,531	-492	18,573	37,048
1.0	500	-13,344	537	3,304	37,968
	1000	-13,261	-543	8,686	37,695
	1500	-15,067	-8,383	18,603	37,383
	1,973	-12,941	Lockup is detected while RIH at 1548.3m	30,086	37,052

TFA Sensitivity Analysis with various Friction Factor – 0.8BPM, 300scfm

Friction Factor	Depth (m)	Lock-up limit (lbf)	RIH Weight (lbf)	POOH Weight (lbf)	Max Pulling Weight at 80% Yield Limit
0.2	500	-26,405	1,093	2,515	37571
	1,000	-13,098	2,056	4,367	37,664
	1,500	-7,530	6,196	2,741	37,352
	1,973	-3,739	3,427	8,248	37,352
0.3	500	-19,383	936	2,458	37,539
	1,000	-10,769	1,801	4,720	37,642
	1,500	-1,089	2,302	6,977	37,542
	1,973	-533	2,805	9,582	37,355
0.7	500	-12,900	682	2,851	37,537
	1,000	-12,499	806	6,476	37,654
	1,500	-12,650	451	11,687	37,526
	1,973	-12,382	123	17,805	37347
1.0	500	-13,531	522	3,199	37553
	1000	-12,529	-212	8,312	37,664
	1500	-13,403	-4,130	17,752	37547
	1,973	-13,543	Lock up is detected while RIH at 1737.4m	28,639	37353

SUMMARY OF TUBING FORCE ANALYSIS AT DEPTH 1,996 M MDDF (XN Nogo)

Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
0 BPM	-3,081	347	20,432	38,573
0.3 BPM	-3,060	202	20,449	38,534
1.1 BPM	-3,040	-779	20,020	37,017
Nitrified (0.8 BPM & 300 SCF/M)	-2,934	-526	20,400	37,339

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.

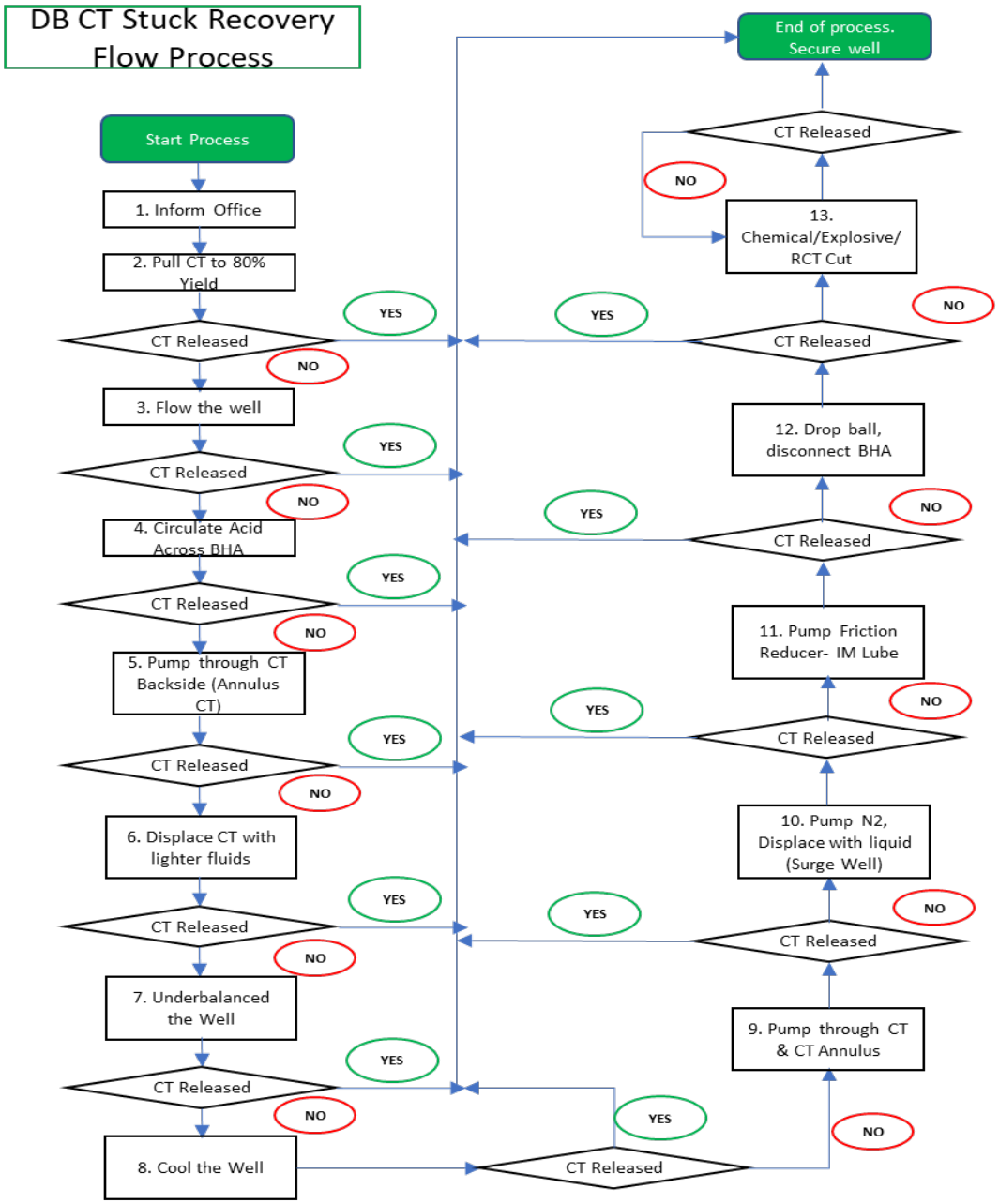
The following are options that may be appropriate depending on the particular circumstances:

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

1-11/16" SpinCat Nozzle

STONEAGE SPINCAT™ SC-168

The StoneAge SpinCat™ SC-168 can be used at operating pressures of 1000 to 5000 psi and flow rates of .7 to 1.33 bpm (30 to 56 gpm). It has a 1" AMMT inlet thread.

Tool Family	StoneAge SpinCat™	
Tool Model	SC-168	
Pressure Range	1-5k psi	70-340 bar
Flow Range	0.7-1.33 bpm	30-56 gpm
Flow Rating	2.3 Cv	
Rotation Speed	150-200 rpm	
Inlet Connection	1" AMMT	
PSI Loss (@ 1 bpm)	330 psi	23 bar
Tension (pull)	Safe load to 8500 lbs	3856 kg
Compression (set down)	Safe load to 12000 lbs	5443 kg
Outside Diameter	1.68 in.	4.3 cm
Overall Length	9.8 in.	25 cm
Weight	4.6 lbs	2 kg
Maximum Temperature	390° F	200° C

APPENDIX VI – CIRCA SIMULATION

Cleanout from depth 1,864 m MDTHF to 1,976 m MDTHF (PXN Plug)

➢ Flow Summary (With 950 psi Reservoir Pressure from E10-11)

SUMMARY OF FLOW RESULTS

Produced Fluids	
Pressure known at:	Perforations
Production Mode:	No Production
Fluid Composition:	Oil Only
Circulated Fluids	
Fluid Composition:	Nitrified Water
Liquid:	0.70 bbl/min
Solids:	0.00 bbl/min
Gas:	350.0 scf/min
Circulation Point:	1975.00 m
HHP Required :	42.77 KW

COMPLETION:

Wellhead Pressure	164.4 psi g
Hydrostatic pressure loss	677.4 psi
Friction pressure loss	110.1 psi
Kinetic pressure loss	-2.0 psi
Restriction pressure loss	0.2 psi
Equivalent Circulation Density[ECD]	3.64 lb/gal (US)
Perforation Pressure	950.0 psi g
Hydrostatic pressure loss	58.0 psi
Friction pressure loss	32.9 psi
Kinetic pressure loss	-0.7 psi
Restriction pressure loss	0.3 psi
Bottom Hole Pressure	1040.5 psi g

FROM CIRCULATION POINT TO WELLHEAD:

Liquid transit time	19 min
Gas transit time	12 min
Annular volume	40.8 bbl
Total liquid volume	15.4 bbl
Total gas volume	25.9 bbl
(Surface equivalent)	4586.3 scf

WORKSTRING:

Liquid:	1008.0 bbl/day
Gas:	0.50 MMscf/day
Pressure at reel rotating joint	3329.4 psi g
Friction pressure loss on reel	1038.9 psi
Hydrostatic pressure loss on reel	6.1 psi
Pressure inside WS at Gooseneck	2284.4 psi g
Hydrostatic pressure loss	-1237.2 psi
Friction pressure loss	1020.5 psi
Equivalent Circulation Density[ECD]	0.99 lb/gal (US)
BHA total pressure loss	1476.8 psi
BHA Hydrostatic loss	-1.9 psi
BHA Friction loss	6.7 psi
BHA Kinetic loss	4.0 psi
Vortex Nozzle	1468.0 psi
Circulation Point pressure	1024.2 psi g

FROM REEL ROTATING JOINT TO CIRCULATION POINT:

Liquid transit time	18 min
Gas transit time	19 min
Displacement Volume	14.1 bbl
Internal Volume	20.3 bbl
Internal liquid volume	13.0 bbl
Internal gas volume	7.3 bbl
(Surface equivalent)	6540.3 scf
Length of Workstring on reel	2119.56 m

➢ Cleanout Summary (With 950 psi Reservoir Pressure from E10-11)

SUMMARY OF HOLE CLEANING RESULTS

Initial Condition:	
% of fill interval occupied by solids before cleanout	80.0 %
Top of fill	1839.99 m
Deepest Circulation point	1975.01 m
Bottom of fill	1975.99 m
Initial Volume of Solids	2.2 bbl
Initial Mass of Solids	1043.6 lb
Solids type:	Carbonate/Silica Scales
Fluid Description:	Nitrified Water
Penetration Hole Cleaning Mode:	
Penetration rate	10.0 ft/min
Penetration time	0.74 hr
Solids volume in the well after penetration	2.2 bbl
Solids mass in the well after penetration	1036.5 lb
Circulation Hole Cleaning Mode:	
Hole circulation time	5.74 hr
Solids volume in the well after circulation	0.0 bbl
Solids mass in the well after circulation	0.0 lb

Volume of Fluids Pumped During Penetration & Circulation:

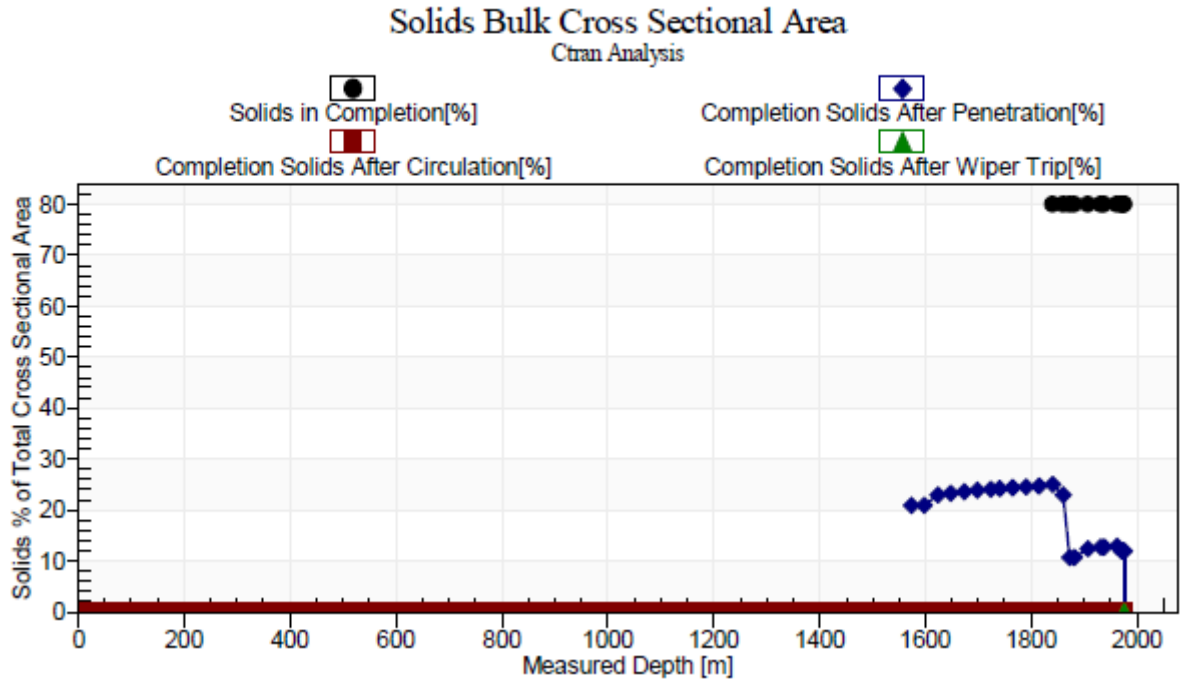
Gas volume	135937.3 scf
Liquid Volume	271.9 bbl
Penetration & Circulation time	6.47 hr

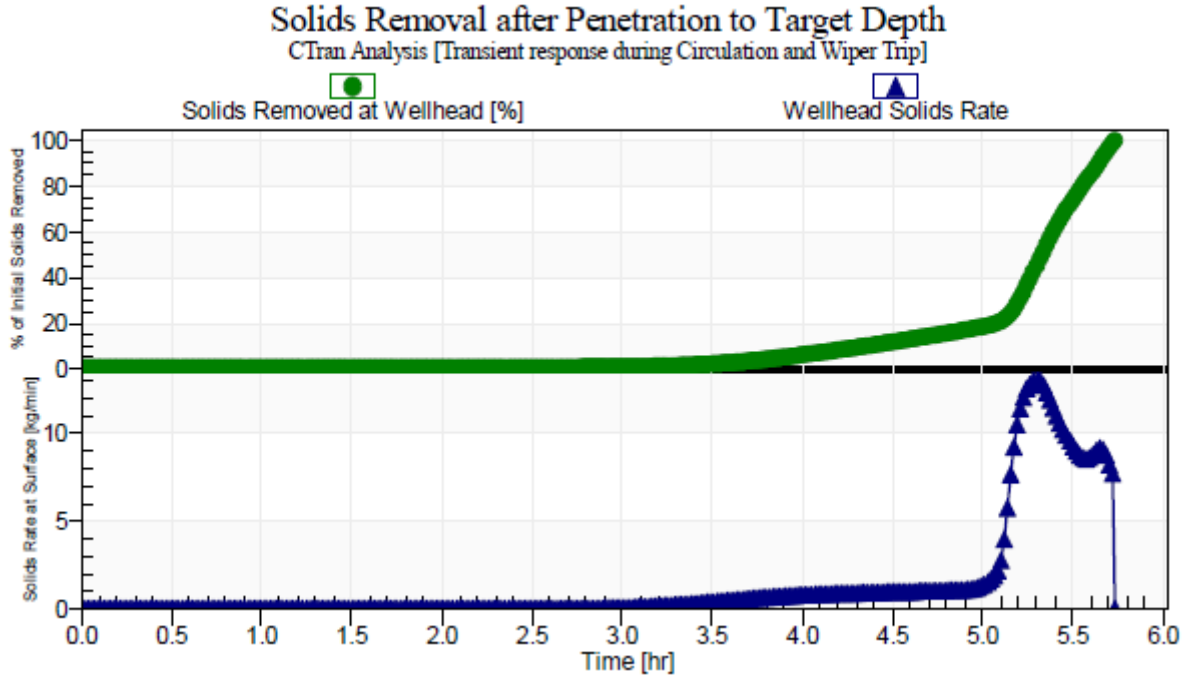
Summary for cleanout :-
Top HUD: 1,840 m MDTHF
Bottom HUD: 1,976 m MDTHF
Pump rate – **0.7 bpm with 350 scfm (Nitrified TIW)**
Penetration speed – 10ft/min
Circulation time – 6 Hours at depth 1,975 m MDTHF
Wiper trip – **Not require**

Cleanout success with 0 % solid left in hole after circulate for 6 hours from 80% of fill (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*
1598.0	198.6	797.2	2533.6	0.0	410	747	0
1623.0	200.3	810.6	2531.5	0.0	424	748	0
1648.0	202.0	824.2	2529.4	0.0	423	749	0
1673.0	203.6	837.8	2527.3	0.0	421	750	0
1698.0	205.3	851.6	2525.2	0.0	420	751	0
1723.0	207.0	865.3	2523.1	0.0	496	752	0
1740.0	208.1	874.7	2521.6	0.0	418	752	0
1765.0	209.8	888.6	2519.4	0.0	417	753	0
1790.0	211.5	902.5	2517.3	0.0	416	754	0
1815.0	213.2	916.5	2515.1	0.0	415	755	0
1840.0	214.9	930.5	2512.8	0.0	416	755	0
1860.0	216.2	941.6	2511.0	0.0	392	755	0
1872.0	217.0	949.9	2509.9	0.0	761	756	0
1882.0	217.7	956.7	2509.0	0.0	597	756	0
1907.0	219.4	974.5	2506.8	0.0	593	758	0
1932.0	221.1	992.5	2504.6	0.0	707	759	0
1937.0	221.4	996.3	2504.2	0.0	590	760	0
1962.0	223.1	1014.3	2501.9	0.0	702	761	0
1971.4	223.8	1021.3	2501.1	0.0	586	762	0
1971.5	223.8	1021.2	2497.0	0.0	681	1910	0
1972.2	223.8	1021.8	2496.0	0.0	681	1910	0
1973.7	223.9	1023.1	2494.0	0.0	680	1911	0
1974.7	224.0	1024.0	2492.7	0.0	680	1911	0


Solids Bulk Cross Sectional Area
Ctran Analysis
Solids in Completion[%]
Completion Solids After Penetration[%]
Completion Solids After Circulation[%]
Completion Solids After Wiper Trip[%]
Solids % of Total Cross Sectional Area
0
10
20
30
40
50
60
70
80
0
200
400
600
800
1000
1200
1400
1600
1800
2000
Measured Depth [m]


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]
0
20
40
60
80
100
0
5
10
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
Time [hr]

Flow Summary (With 1,350 psi Reservoir Pressure from E12-13B)

SUMMARY OF FLOW RESULTS

Produced Fluids	
Pressure known at:	Perforations
Production Mode:	No Production
Fluid Composition:	Oil Only
Circulated Fluids	
Fluid Composition:	Nitrified Water
Liquid:	0.80 bbl/min
Solids:	0.00 bbl/min
Gas:	300.0 scf/min
Circulation Point:	1975.00 m
HHP Required :	52.52 KW

COMPLETION:

Wellhead Pressure	272.1 psi g
Hydrostatic pressure loss	949.6 psi
Friction pressure loss	131.7 psi
Kinetic pressure loss	-3.8 psi
Restriction pressure loss	0.4 psi
Equivalent Circulation Density[ECD]	4.78 lb/gal (US)
Perforation Pressure	1350.0 psi g
Hydrostatic pressure loss	16.9 psi
Friction pressure loss	0.5 psi
Kinetic pressure loss	-0.2 psi
Bottom Hole Pressure	1367.2 psi g

FROM CIRCULATION POINT TO WELLHEAD:

Liquid transit time	23 min
Gas transit time	16 min
Annular volume	40.8 bbl
Volume below circulation point	0.4 bbl
Total liquid volume	20.5 bbl
Total gas volume	20.8 bbl
(Surface equivalent)	5159.4 scf

WORKSTRING:

Liquid:	1152.0 bbl/day
Gas:	0.43 MMscf/day
Pressure at reel rotating joint	3578.4 psi g
Friction pressure loss on reel	1206.7 psi
Hydrostatic pressure loss on reel	6.6 psi
Pressure inside WS at Gooseneck	2365.2 psi g
Hydrostatic pressure loss	-1223.5 psi
Friction pressure loss	805.1 psi
Equivalent Circulation Density[ECD]	1.92 lb/gal (US)
BHA total pressure loss	1432.6 psi
BHA Hydrostatic loss	-1.8 psi
BHA Friction loss	14.8 psi
BHA Kinetic loss	3.8 psi
Vortex Nozzle	1415.9 psi
Circulation Point pressure	1350.8 psi g

FROM REEL ROTATING JOINT TO CIRCULATION POINT:

Liquid transit time	17 min
Gas transit time	21 min
Displacement Volume	14.1 bbl
Internal Volume	20.3 bbl
Internal liquid volume	13.5 bbl
Internal gas volume	6.9 bbl
(Surface equivalent)	6305.1 scf
Length of Workstring on reel	2119.56 m

Cleanout Summary (With 1,350 psi Reservoir Pressure from E12-13B)

SUMMARY OF HOLE CLEANING RESULTS

Initial Condition:	
% of fill interval occupied by solids before cleanout	80.0 %
Top of fill	1839.99 m
Deepest Circulation point	1975.01 m
Bottom of fill	1975.99 m
Initial Volume of Solids	2.2 bbl
Initial Mass of Solids	1043.6 lb
Solids type:	Carbonate/Silica Scales
Fluid Description:	Nitrified Water
Penetration Hole Cleaning Mode:	
Penetration rate	10.0 ft/min
Penetration time	0.74 hr
Solids volume in the well after penetration	2.2 bbl
Solids mass in the well after penetration	1036.5 lb
Circulation Hole Cleaning Mode:	
Hole circulation time	8.00 hr
Solids volume in the well after circulation	1.8 bbl
Solids mass in the well after circulation	866.6 lb
Wiper Trip Hole Cleaning Mode:	
Wiper Trip Scheme:	User Specified rate, Tornado not
Wiper trip time	1.89 hr
Solids volume in the well after wiper trip	0.0 bbl
Solids mass in the well after wiper trip	0.0 lb

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

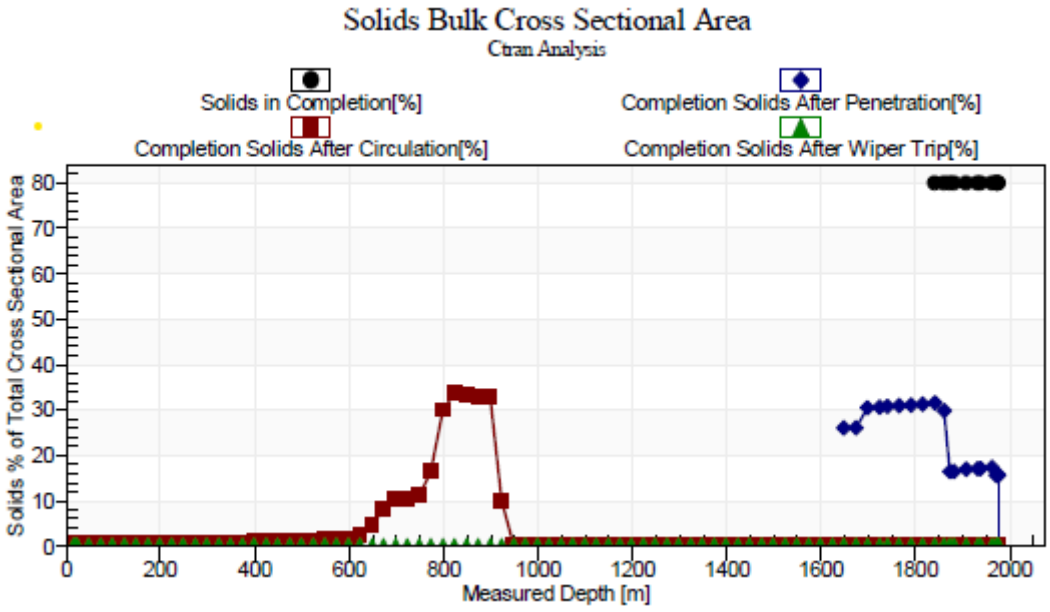
Gas volume	191317.6 scf
Liquid Volume	510.2 bbl
Penetration, Circulation & Wiper Trip time	10.63 hr

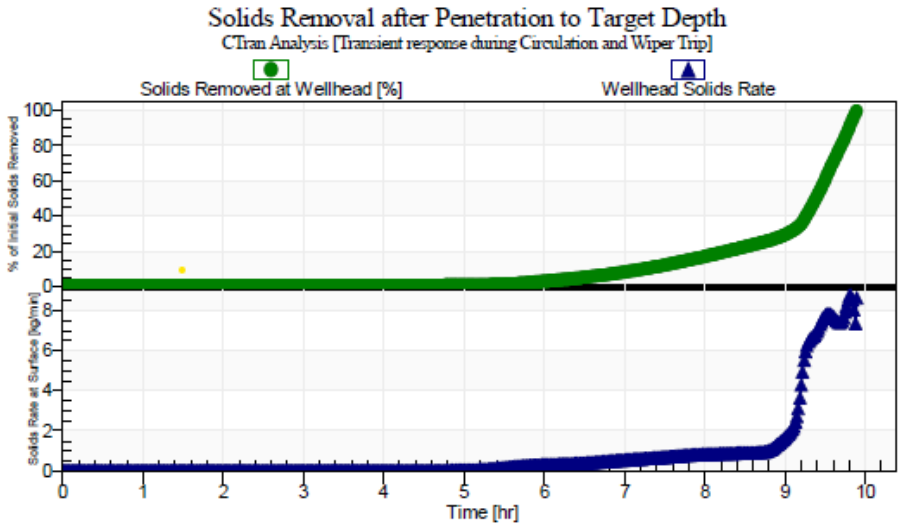
Summary for cleanout :-
Top HUD: 1,840 m MDTHF
Bottom HUD: 1,976 m MDTHF
Pump rate – 0.8 bpm with 300 scfm (Nitrified TIW)
Penetration speed – 10ft/min
Circulation time – 8 Hours at depth 1,975 m MDTHF
Wiper trip speed – 10 ft/min until 1,630 m MDTHF

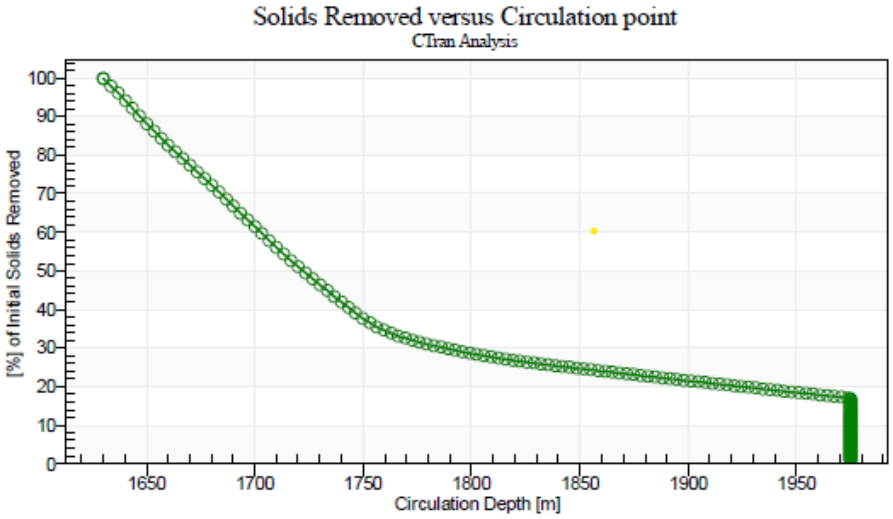
Cleanout success with 0 % solid left in hole from 80% of fill (assumption).

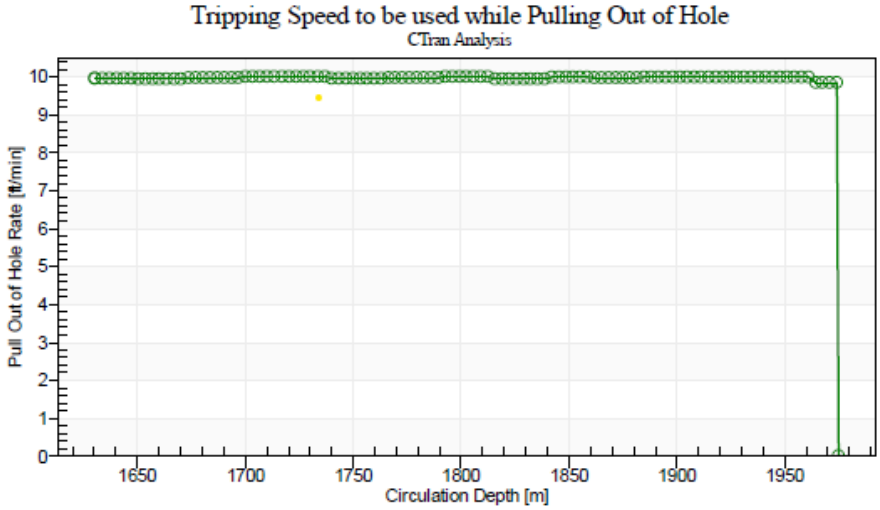
Flow State (continued)

Measured Depth[Flow] m	Temperature	Completion Pressure	Workstring Pressure	Concentric Pressure	Completion Liquid Velocity hr	Workstring Liquid Velocity m	Concentric Liquid Velocity ft/min
1598.0	192.7	1089.7	2754.9	0.0	231	947	0
1623.0	194.3	1101.5	2756.8	0.0	230	948	0
1648.0	195.9	1113.3	2758.8	0.0	230	949	0
1673.0	197.6	1129.0	2760.7	0.0	377	950	0
1698.0	199.2	1145.5	2762.7	0.0	413	951	0
1723.0	200.8	1162.1	2764.6	0.0	488	952	0
1740.0	201.9	1173.5	2765.9	0.0	412	953	0
1765.0	203.5	1190.2	2767.9	0.0	411	953	0
1790.0	205.1	1206.9	2769.8	0.0	411	954	0
1815.0	206.7	1223.8	2771.7	0.0	411	955	0
1840.0	208.3	1240.7	2773.5	0.0	412	956	0
1860.0	209.6	1253.9	2775.0	0.0	392	956	0
1872.0	210.4	1263.7	2775.8	0.0	709	956	0
1882.0	211.0	1272.1	2776.6	0.0	592	957	0
1907.0	212.6	1293.2	2778.5	0.0	589	958	0
1932.0	214.2	1314.5	2780.4	0.0	703	959	0
1937.0	214.6	1318.8	2780.8	0.0	589	960	0
1962.0	216.2	1340.1	2782.8	0.0	700	961	0
1971.4	216.8	1348.2	2783.6	0.0	581	961	0
1971.5	216.8	1347.9	2779.5	0.0	661	2323	0
1972.2	216.9	1348.5	2776.9	0.0	661	2323	0
1973.7	217.0	1349.9	2771.4	0.0	661	2324	0
1974.0	217.0	1350.0	2770.4	0.0	662	2324	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]

Client: **PCSB**
Well: **D-31**
Field **Dulang D**
Job: **Sand Cleanout from 1,864 m until 1,973 m MDTHF**
Date: **16/6/2024**

Dimension Bid (M) Sdn Bhd
Time Planner

Total Time 35:46 hh:mm

BBLS	GAL N2
1,162.8	3,323.8

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 1,864m MDTHF. Perform jet clean across every SPM for 2 passes	FLUID 1 - TIW	4:00	14:11	10:11	0.3	0	0	6,115	10.0	183.5	0
2	Spot 5 bbls of 15% HCl Acid on top of HUD & soak for 2 hours	FLUID 4 - 15% HC	14:11	16:41	2:30	0.5	0	6,115	6,115		75.0	0
3	Increase pump rate to establish return on surface prior penetrate HUD at 1,864 m MDTHF	FLUID 2 - Nitrified	16:41	19:49	3:07	0.8	300	6,115	6,115	0.0	150.0	604
4	Start Penetrate HUD 30m/100ft	FLUID 2 - Nitrified	19:49	19:59	0:10	0.8	300	6,115	6,215	10.0	8.0	32
5	Circulate 5bbls Gel	FLUID 3 - Gel	19:59	20:05	0:06	0.8	300	6,215	6,215	0.0	5.0	20
6	Wiper Trip to 10m above previous HUD	FLUID 2 - Nitrified	20:05	20:18	0:13	0.8	300	6,215	6,085	10.0	10.4	42
7	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	20:18	20:41	0:23	0.8	300	6,085	6,315	10.0	18.4	74
8	Circulate 5bbls Gel	FLUID 3 - Gel	20:41	20:47	0:06	0.8	300	6,315	6,315	0.0	5.0	20
9	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	20:47	21:00	0:13	0.8	300	6,315	6,185	10.0	10.4	42
10	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	21:00	21:23	0:23	0.8	300	6,185	6,415	10.0	18.4	74
11	Circulate 5bbls Gel	FLUID 3 - Gel	21:23	21:29	0:06	0.8	300	6,415	6,415	0.0	5.0	20
12	Wiper Trip to 10m/30ft above previous HUD	FLUID 2 - Nitrified	21:29	21:42	0:13	0.8	300	6,415	6,285	10.0	10.4	42
13	RIH HUD + 30m/100ft	FLUID 2 - Nitrified	21:42	22:01	0:18	0.8	300	6,285	6,474	10.0	15.1	61
14	Circulate 5bbls Gel	FLUID 3 - Gel	22:01	22:07	0:06	0.8	300	6,474	6,474	0.0	5.0	20
15	CBU for 8 hours. Flag #1 CT at surface at depth 1,976 m MDTHF	FLUID 2 - Nitrified	22:07	6:07	8:00	0.8	300	6,474	6,474		384.0	1,547
16	Wiper trip to 1,630 m MDTHF. Perform jet clean across every SSD for 2 passes	FLUID 3 - Gel	6:07	9:53	3:45	0.8	300	6,474	5,348	5.0	180.2	726
17	RIH back to 1,942 m MDTHF	FLUID 1 - TIW	9:53	10:44	0:51	0.3	0	5,348	6,371	20.0	15.3	0
18	Spot 63 bbls of 7.5% HCl Acid (tubing pickling) while POOH to surface at 30 ft/min	FLUID 5 - 7.5% HC	10:44	14:16	3:32	0.3	0	6,371	0	30.0	63.7	0
19	Soak for 1 hour	FLUID 1 - TIW	14:16	15:46	1:30	0.0	0	0	0		0.0	0

APPENDIX VII – LAB ANALYSIS

DIMENSION BID

CERTIFICATE OF ANALYSIS

Client : PCSB - PMA **Test** : Dissolution Test
Field : Dulang **Date of Issued** : 5th July 2023
Well ID : D31

Test Properties

No	Descriptions	Details
1.	Test temperature	55 °C & 68 °C
2.	Test chemical	15% Hydrochloric Acid (15% HCl)
3.	Soaking period	4 hours
4.	Sample appearance	

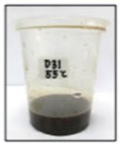
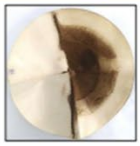
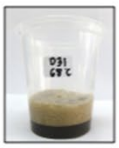
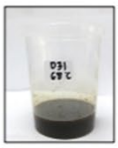
Observation & Result

No	Descriptions	55 °C	68 °C
1.	Weight of Sample (Initial Weight)	1.1982 g	1.0126 g
2.	Dried Weight After Treatment	0.0932 g	0.0662 g
3.	Dissolved Weight	1.1050 g	0.9464 g
4.	% Dissolved $(\frac{\text{Dissolved Weight}}{\text{Initial Weight}} \times 100)$	**92.22 %**	**93.46 %**

DIMENSION BID

CERTIFICATE OF ANALYSIS

Client : PCSB - PMA **Test** : Dissolution Test
Field : Dulang **Date of Issued** : 5th July 2023
Well ID : D31

Temperature	Description	Observation Photo		
		Before	After	After Drying
55 °C	• Sample reacts rapidly when in contact with 15% HCl. • Foam was created immediately but it disappeared after 5 minutes. • 92.22% of the sample managed to be dissolved after 4 hours soaking period.			
68 °C	• Sample reacts rapidly when in contact with 15% HCl. • Foam was created immediately but it disappeared after 5 minutes. • 93.46% of the sample managed to be dissolved after 4 hours soaking period.			

This re 2 / 2

Nadia Shahirah

PETRONAS Carigali Sdn Bhd
SGS File No. KE23-00716

SGS

Particle Size Distribution Data
by Sieve

Sample ID: KE23-00716.002 (WELL D31)

Sieve Size (Micron)	Method	Result	Unit
850	KUL-SOP-024	96.49	wt%
600		1.98	
300		1.12	
212		0.05	
90		0.10	
53		0.01	
Catch Pan		0.01	
Total Loss		0.23	

SGS

ilac-MRA STANDARDS MALAYSIA ACCREDITED SAMM 284

Analytical Report: KE23-00716.002

Date: 28/03/2023
PETRONAS CARIGALI SDN BHD
Operasi Semenanjung Malaysia
Tingkat 1 & 2 Kompleks Pejabat Petronas
Kemaman
Kerteh
MALAYSIA
24300

The sample(s) to which the findings recorded herein (the "Findings") relate was(were) drawn and / or provided by the Client or by a third party acting at the Client's direction. The Findings constitute no warranty of the sample's representativeness of any goods and strictly relate to the sample(s). The Company accepts no liability with regard to the origin or source from which the sample(s) is/are said to be extracted.

This laboratory is accredited under ISO/IEC 17025. The results reported herein have been performed in accordance with the laboratory's term of accreditation except calibrations/tests marked with an asterisk (*) in this report which are not within the scope of accreditation for our laboratory.

CLIENT ORDER NUMBER :		SGS ORDER NO.:	10249675
CLIENT ID :	LSR NO: 2023-03-05		
LOCATION :	Dulang B (DLB)	PRODUCT DESCRIPTION :	SOLID
SAMPLE SOURCE :	Offshore Platform	SOURCE ID :	WELL D31
SAMPLE TYPE :	As submitted	SAMPLE BY :	Client
SAMPLED :	--	RECEIVED :	15/03/2023
ANALYSED :	26/03/2023 - 27/03/2023	COMPLETED :	27/03/2023
SAMPLE COMMENT :	**PO: 3400313089**		

PROPERTY	METHOD	RESULT	UNITS
Analysis for Loss on ignition	KUL SOP 037 (In-House Method based on ASTM D7348)		
Moisture Content		3.96	% (m/m)
Organic Content		6.34	% (m/m)
Inorganic Content		93.66	% (m/m)
Trace Element in Petroleum Product and Lubricant by WDXRF *	KUL SOP 023 (In-House Method based on Manufacturer's Model Bruker S6 Jaguar)		
Silicon, Si *		2.25	% (m/m)
Iron, Fe *		0.94	% (m/m)
Phosphorus, P *		0.49	% (m/m)
Alumunium, Al *		0.13	% (m/m)
Sulphur, S *		0.46	% (m/m)
Calcium, Ca *		44.73	% (m/m)
Sodium, Na *		0.30	% (m/m)
Barium, Ba *		0.17	% (m/m)
Magnesium, Mg *		0.26	% (m/m)
Strontium, Sr § *		0.37	% (m/m)
Identification of Compound and Scale by X-Ray Diffractometer *	KUL SOP 045 (In-House Method based on Manufacturer's Model Bruker)		
Compound 1 (Major) *		Aragonite	---
Compound 2 (Minor) *		Quartz	---
Compound 3 (Minor) *		Magnesium Iron Oxide	---

APPENDIX VIII – DECISION TREE