DIMENSION BID

PETRONAS

DULANG D-06S
ZONE SHUT OFF

Revision:	4
Prepared for:	Pravin Nair Venugopalan
Date Prepared:	11th May 2024
Well:	D-06S
Field:	Dulang D
Operation Region:	PMA
Prepared by:	Muhammad Ameerul Zaeem
Phone:	+6011 2903 3294
Email:	ameerul@neudimension.com

DESIGN VERIFICATION

PREPARED BY DB CTS Field Engineer	 Muhd Ameerul Zaeem	11/05/2024 Date
REVIEWED BY DB CTS Technical Advisor	 Kung Yee Han	11/05/2024 Date
APPROVED BY DB CTS General Manager	 Aliff Adenan	11/05/2024 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.

DISTRIBUTION LIST

No	Personnel	Company	Name	Email
1	Well Intervention Engineer	PCSB	Pravin Nair Venugopalan	pravin.venugopalan@petronas.com.my
2	Well Service Supervisor (WSS)	PCSB	TBA	TBA
3	Offshore Installation Manager (OIM)	PCSB	TBA	TBA
4	Tech Professional	PCSB	Izwan B A Jalil	izwanjalil@petronas.com
5	Cluster Head	PCSB	Ahmad Hafizi	hafizi.zaini@petronas.com
6	Head of well Intervention	PCSB	Eddy Samaile	Eddysamaile@petronas.com
7	Material Coordinator (Logistics)	DB – Kemaman	Marzokey	marzokey@neudimension.com
8	Service Supervisor	DB – Kemaman	TBA	TBA
9	Field Engineer CT Services	DB – Kemaman	M. Ameerul Zaeem	ameerul@neudimension.com
10	Junior Field Engineer CT Services	DB – Kemaman	Haziq Fikri	fikri.roslan@neudimension.com
11	Operation Engineer CT Services	DB – Kemaman	Mohammad Faizal Ali	faizal.ali@neudimension.com
12	Technical Advisor CT Services	DB – Kemaman	Kung Yee Han	yeehan.kung@neudimension.com
13	Field Service Manager CT Services	DB – Kemaman	Mohd Khairul Ridhwan	khairul.ridhwan@neudimension.com
14	General Manager CT Services	DB – Kemaman	Aliff Amirul Adenan	aliff.adenan@neudimension.com
15	HSE Supervisor	DB – Kemaman	Ahmad	ahmad@neudimension.com

PERSONNEL CONTACT

Any means of following doubt / unusual parameters / Emergency, please contact Dimension Bid personnel in onshore immediately.

No	Name	Position	Company	Location	Contact No
1	M Ameerul Zaeem	Field Engineer	DB	Kemaman	011 – 2903 3294
2	Haziq Fikri	Junior Field Engineer	DB	Kemaman	010 – 404 8454
3	Alif Adenan	General Manager	DB	Kemaman	011 – 1225 7044
4	Mohd Khairul Ridhwan	Field Services Manager	DB	Kemaman	014 – 515 4452
5	Kung Yee Han	Technical Advisor	DB	Kemaman	019 – 610 2088
6	Mohammad Faizal Ali	Operation Engineer	DB	Kemaman	013 – 736 1046

REVISION HISTORY

Rev. No	Section	Date	Revised By
0	All	8/4/2024	M. Ameerul Zaeem
1	To apply 300 psi on CT Annulus through kill line & contain pressure during injectivity test & cementing.	21/4/2024	M. Ameerul Zaeem
2	To change volume of cement & CR setting depth	7/5/2024	M. Ameerul Zaeem
3	To change cement volume to 27 bbls & update procedure for CR integrity test	9/5/2024	M. Ameerul Zaeem

ACRONYM

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

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

TABLE OF CONTENT

OBJECTIVES

The objective of this job is to perform zone shut off on zone E-2A prior rig entry for Plug & Abandonment (P&A) activity. CTU operation consists of 3 CT runs with 1 contingency (CT Cleanout until CA Plug (2,138m MDTHF) Setting Depth).

BACKGROUND

Dulang D-06 is a dual string oil producer with 2-7/8" completion which was completed on November 1995 with maximum deviation of 64 degree at 658 m MDTHF. Currently both short & long string are in shut in condition. PCSB has engaged DB to perform zone shut off on zone E-2A via CTU prior to Plug & Abandonment (P&A) activity.

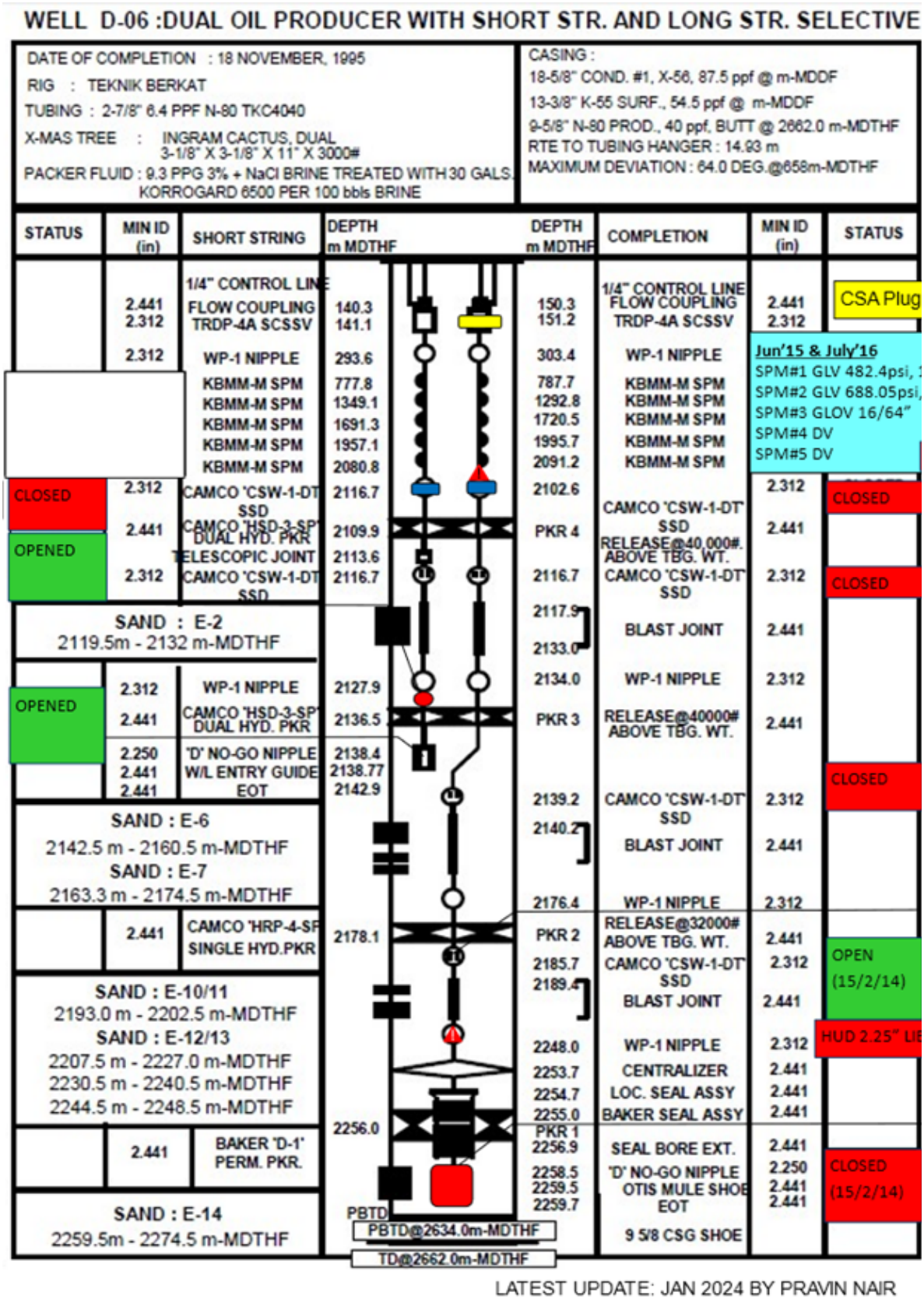
WELL DATA

Input Parameter	Parameter Value
Field	Dulang
Well	D-06S
Max. Deviation (degrees)	64 degree @ 658 m MDTHF
Min. Restriction (inch)	2.25" ('D' Nogo Nipple)
Tubing Specification	2-7/8" Production Tubing (Refer Well Schematic)
Type of Fluid & Density	N/A
Top of Fluid	No fluid level detected
Current Well Status	Both String in Shut-In Condition
Depth of zone	E2A (2119.5 – 2132m MDTHF)
Reservoir Pressure (psi)	E2A: 953 psi
Reservoir Temperature (deg F)	E2A: 224 deg F
Porosity	E2A: 0.278
Permeability (mD)	E2A: 188
Fracture Gradient	0.7 psi/ft
H_2S Content	Not available
CO_2 Content	Not available
Mercury, HG	Not available
Additional Information / Notes / Special Requirement:	
• Leak detected at 2,129.5 m MDTHF	

OPERATION SUMMARY

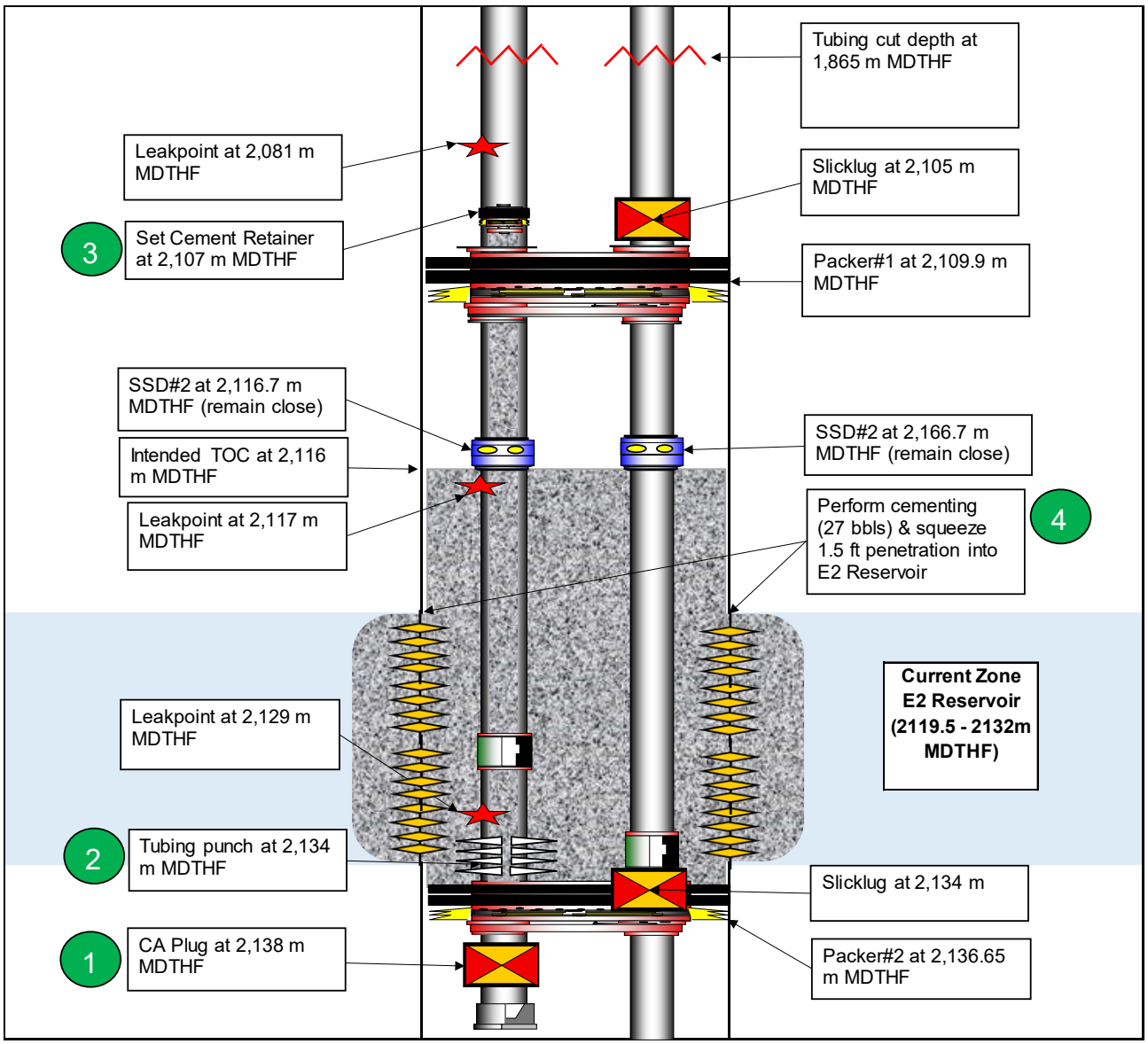
Item	*Job Description*	*Remark*
A	Slickline	1. Retrieve MA Plug at SSD#1 2. TCC 3. Set CA Plug at 2,138 m MDTHF 4. Tubing Punch at 2,134 m MDTHF
B	Coiled Tubing Operation	Contingency CT Cleanout until CA Plug (2,139m MDTHF) Setting Depth
C	Coiled Tubing Operation	1. CT Run#1 Drift & Correlation Run Until CA Plug at 2,138 m MDTHF 2. CT Run#2 Set Cement Retainer at 2,107 m MDTHF and Perform Cementing (27 bbls) 3. CT Run#3: Post Cementing CT Cleanout Until Top of Cement Retainer at 2,107 m MDTHF
D	Bullheading Operation	Integrity Test (if require)

WELL DIAGRAM

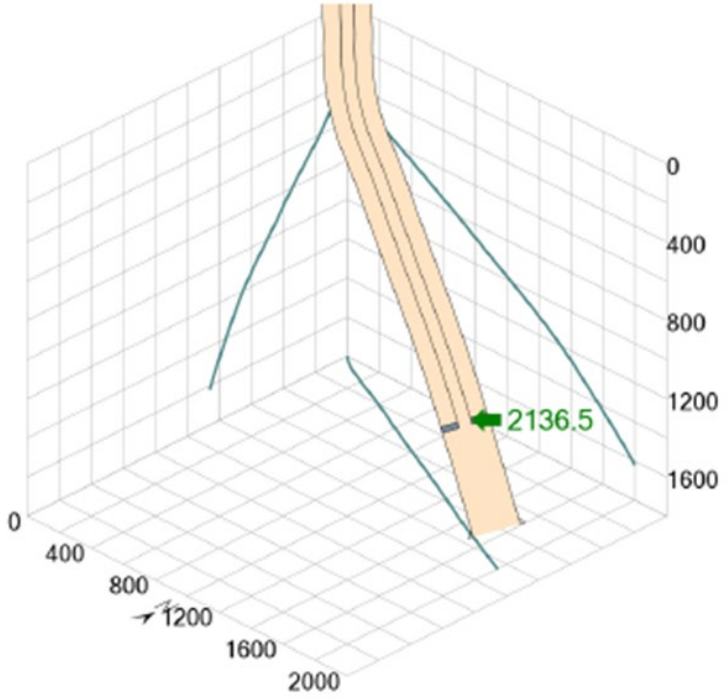


LATEST UPDATE: JAN 2024 BY PRAVIN NAIR

WELL CEMENTING ILLUSTRATION



WELL 3D PLOT



Well name: Dulang D06
Total depth: 2671.0 m
Max Inclination: 64.5° at 791.5 m
Max DLS: 5.293 °/100ft at 150.0 m
Min ID: 2.441 in at surface.
WHP: 150 psi

Input Parameter	*Parameter Value*
Well	Dulang D-06
Trajectory Until Depth	2,662 m MDTHF
Max. Deviation (degrees)	64.5 degree at 791.5 m MDTHF
Min. Restriction (inch)	2.25” (‘D’ Nogo Nipple) @ 2,138 m MDTHF

TREATMENT VOLUME

Description	Details
Tubing Specification	2-7/8" 6.4ppf# N-80
Production Casing Specification	9-5/8" 40ppf# N-80

Dulang D-06 **Downhole Calculation** **Prepared Date: 9/5/2024**

Tubing (Short String)

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	2 7/8	2.441	6.4							0.00579	14.93	2102.00	49	6897	**6848**	**40**
SSD#1 to SSD#2	2 7/8	2.441	6.4							0.00579	2102.00	2116.70	6897	6945	**48**	**0.3**
SSD#2 to Leakpoint	2 7/8	2.441	6.4							0.00579	2116.70	2129.50	6945	6987	**42**	**0.2**
Leakpoint to EOT	2 7/8	2.441	6.4							0.00579	2129.50	2142.90	6987	7031	**44**	**0.3**
															TOTAL	**40**

A-Annulus

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	2 7/8	2.441	6.4	0.05977	14.93	2102.00	49	6897	**6848**	**409**
SSD#1 to Packer#1	9 5/8	8.835	40	2 7/8	2.441	6.4	2 7/8	2.441	6.4	0.05977	2102.00	2109.90	6897	6923	**26**	**2**
															TOTAL	**411**

B-Annulus

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	
Packer#1 to Packer #2	9 5/8	8.835	40	2 7/8	2.441	6.4	2 7/8	2.441	6.4	0.05977	2109.90	2136.50	6923	7010	**87**	**5**
															TOTAL	**5**

Cement 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	
Cement Retainer to Nippleless Plug	2 7/8	2.441	6.4							0.00579	2107.00	2136.50	6913	7010	**97**	**0.6**
TOC at SSD#2 to Packer #2	9 5/8	8.835	40	2 7/8	2.441	6.4	2 7/8	2.441	6.4	0.05977	2116.00	2136.00	6943	7008	**66**	**4**
															Total	**4**

1.5 ft Penetration - Zone E2A

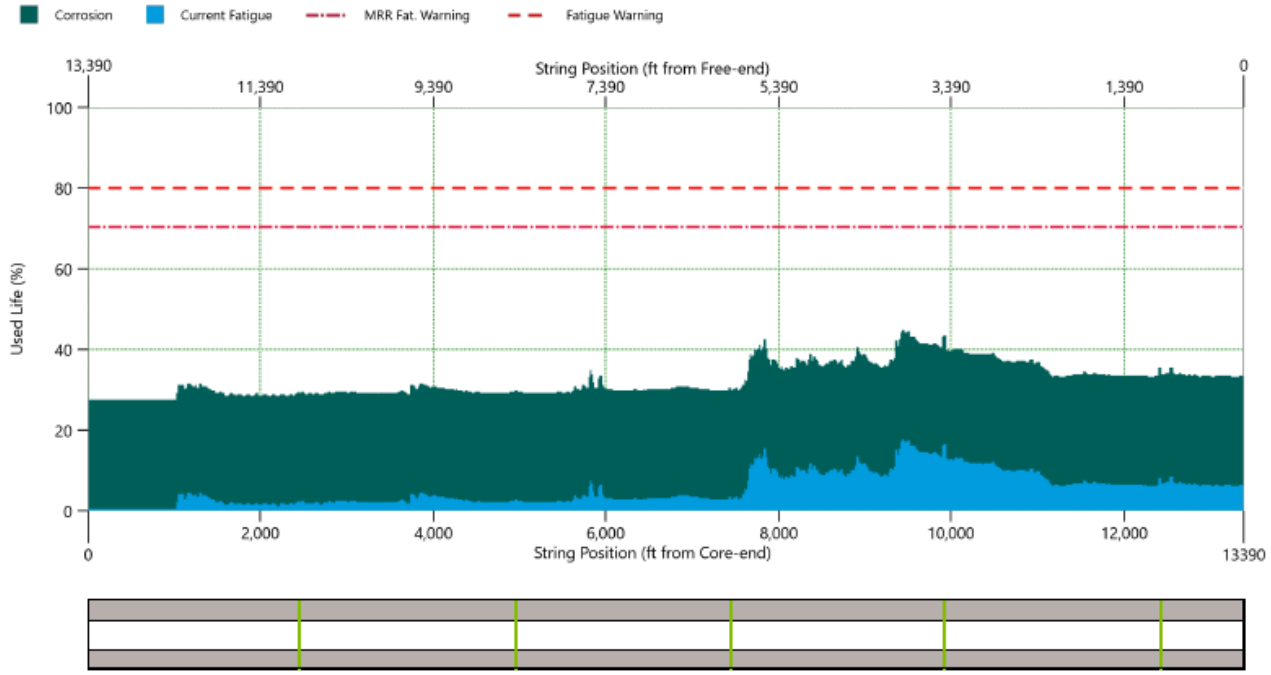
Type	External Pipe			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E-2A Reservoir (1.5 ft Penetration)		44.835		8 5/6			18	1.87686	2119.50	2132.00	6954	6995	**41**	**77**
													Porosity	**0.278**
													Total	**21**
												Total Cement Volume		**27**

CT STRING INFORMATION

OD (in)	Spec	W/T (in)	ID (in)	Length (ft)
1.5	HS-90	0.125	1.25	13,389
CT Volume: 20.3 bbls				

CT STRING FATIGUE

- Current **used life** for Tenaris #40146 is at **44.55%**

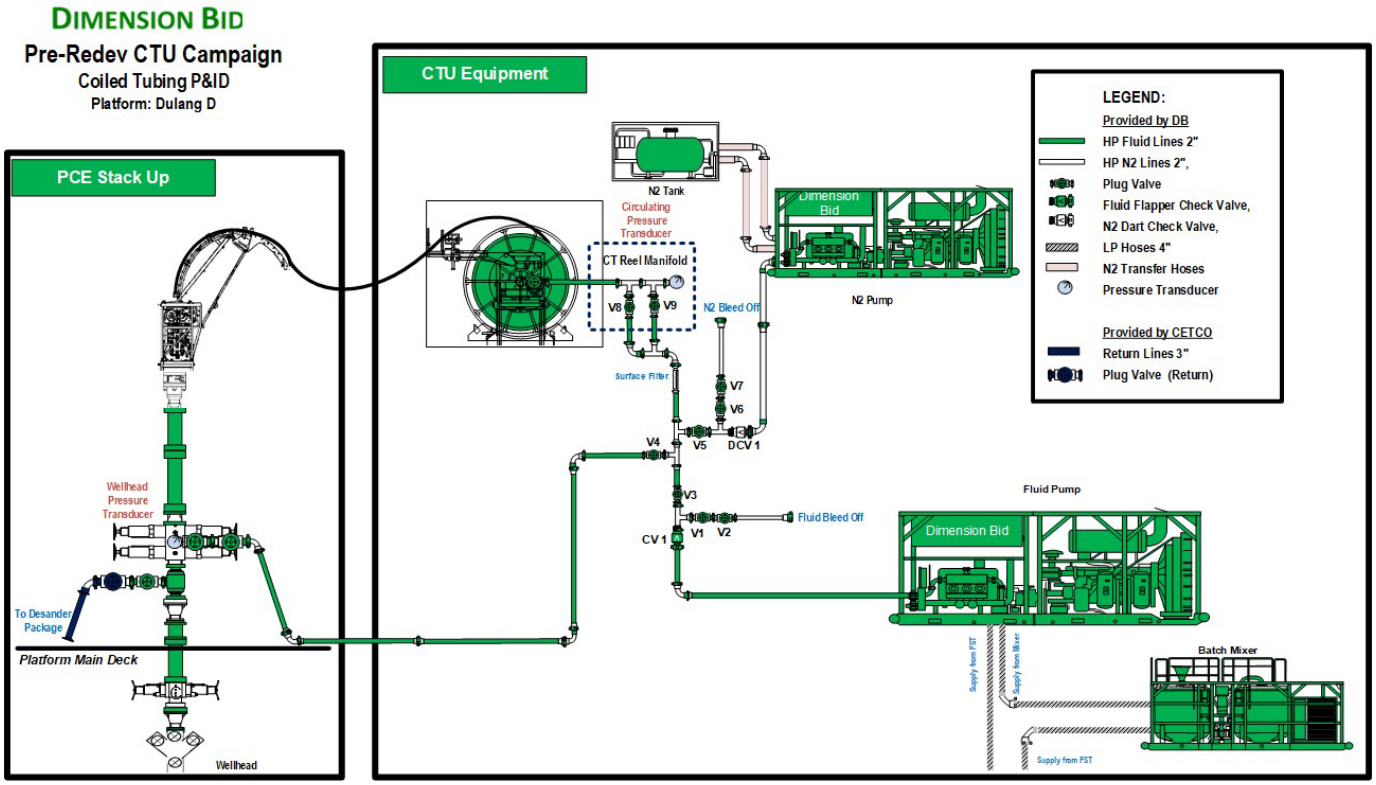


Run #	Date	Field Name	Well Num	Job type	Cum. Run ft	CT cut ft	New CT leng ft	Job Fatigue %	Job Corrosion %	Max Fatigue	Cum. Corrosion %	Used String Life %
N/A	26-Aug-23	Dulang-D	D-15L	Trim Coiled 57 ft	N/A	57	15,586	0	0	0	0	30.44
17	29-Aug-23	Dulang-D	D-15L	Sand Clean Out	155,003		15,586	3.2	2	3.74	17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

MAXIMUM ALLOWABLE SURFACE TREATING PRESSURE (MASTP)

Fluid	Fluid Density, ppg	Interval TVD, ft	Hyd. Pressure, psi	Fracture Pressure, psi	STP, psi	80% MASTP, psi
Sea Water	8.50	4,124	1,882	2,887	1,005	800
Cement Slurry	15.0	75				

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.

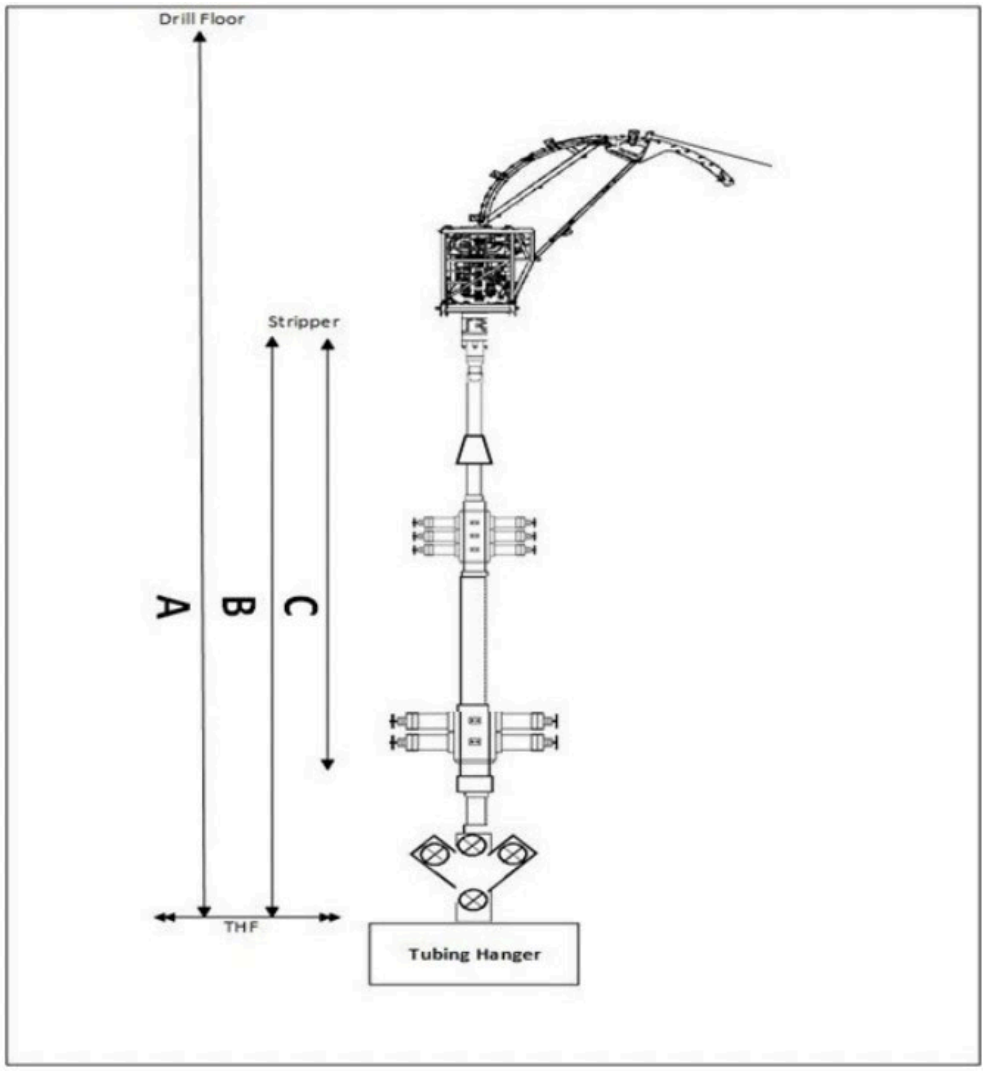
    *Observe indicator pin to confirm that all rams are in good working condition.

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. Pickle CT String with 7.5% HCl acid to remove internal rust & foreign debris.
20. Circulate the string with water until clean return is seen prior to proceed with pressure test CT Connector.

21. Pressure up the CT string to 7,000 psi gradually by 500 psi increment then hold for 10 minutes.
22. Open the needle valve to release the pressure slowly.
23. Make up the BHA onto the string as per BHA diagram provided.
24. Use the jacking frame to pick up the injector and risers then connect to the Combi BOP. Secure down the injector assembly with chains.
25. 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	

26. 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 through the CT String.
7. Close the equalizing valve and begin pressure test the pipe ram to 3,000 psi, hold for 10 minutes.
8. When the tests are complete, bleed off the pressure.

OPERATIONAL PROCEDURE

All depths specified below are in m-MDTHF.

CT CONTINGENCY#1: CLEANOUT UNTIL CA PLUG (2,139 M WLTHF) SETTING DEPTH

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

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

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

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

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

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

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

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

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

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

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

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

3.3. Rig up CT package and surface treating line.

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

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

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

3.7. Install the Pull and Pressure Test Sub.

3.8. Activate Real Time data sharing (Max Completion) & ensure data is readable at town.

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

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

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

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

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

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

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

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

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

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

   8.1. For low pressure:

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

   8.2. For high pressure:

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

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

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

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

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

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

CV Opening Turns	LMV Opening Turns

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

12.4. Manipulate surface valve to the following position:

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

13. Start RIH while pumping TIW at 0.3bpm until 2,097 m MDTHF (10m above Cement Retainer setting depth) or last encountered HUD depth with reference to previous Slickline HUD.

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

13.2. Maximum coil speed RIH is **30-50 ft/min.**

13.3. Closely observe weight indicator in control cabin while RIH.

13.4. Conduct pull test minimum of every 300m (1,000ft) interval, use CT Fatigue graph as reference. Record RIH, Hanging and POOH weight in treatment report.

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

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

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

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

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

14. Once BHA reached 2,097 m MDTHF (10m above Cement Retainer setting depth), 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

15. Continue RIH & perform cleanout while pumping at 1.1 bpm starting at depth 2,097 m MDTHF until 2,142 m MDTHF (EOT).

16. Once CT at 2,142 m MDTHF, proceed to step 20 to perform high jetting at Cement Retainer & Plug setting depth.

16.1. If encounter HUD, perform high jetting at 1.1 bpm with 5 bbls of 15% HCl acid on top of HUD.
If no progress, proceed to spot 5 bbls of 15% HCl acid on top of HUD and soak for 2 hours. (Please refer chemical recipe for 15% HCl acid as per below table)

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

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

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

17. Pick up CT to safe depth (550 m above HUD) and waiting on soak time of 2 hours.
18. Upon completion of acid soak, open return line & continue RIH to HUD depth & attempt to penetrate again.
    18.1. If unsuccessful, repeat step 16 for at least 2 times.
    18.2. During circulation, if return is tested to be < pH 7, inject soda ash using chemical injection pump to the surface return line to neutralize the acid.

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

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

19. Upon completion of acid unload, perform circulate bottoms up with 80 bbls of TIW (2x tubing volume) at 1.0 bpm.
20. POOH CT to surface while pumping at idle rate at 0.3 bpm.
    20.1. Make 2 passes across depth 2,107 m MDTHF (Cement Retainer Setting Depth). Perform jet clean 10 m above & 10 m below at high rate.
    20.2. Make 2 passes across depth 2,139 m MDTHF (CA Plug Setting Depth). Perform jet clean 5 m above & 5 m below at high rate.
21. Once at surface, handover to slickline for TCC.

CT RUN#1: DEPTH CORRELATION & DRIFT RUN WITH 2.20" FLUTED CENTRALIZER

22. Perform pumping calibration test at surface prior for operation. (Ensure pump rate/ volume at pump, tally with DAS at cabin and volume inside the storage tank). Witnessed and verify by WSS.

    NOTE: During the cementing operation, in the event pump rate doesn't tally with DAS, to always use volume inside the mixing / supply tank as reference.

23. Pickle the CT String with 10 bbls of 7.5% HCl, followed by 25 bbls of TIW and neutralization fluid (soda ash) to remove internal rust and ensure no foreign debris inside the CT string. If CT Pickle has been done prior CT Contingency#1, this will be not necessary. Please refer below 7.5% HCl mixing chemical recipe:

7.5% HCl (CT Pickle)			4,200	gals	10	bbls	Description
Products	Concentration		Volume				
Injection Water	798	gptg	335	gals	7.98	bbls	Base Fluid
33% HCl	202	gptg	85	gals	2.02	bbls	Raw acid

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

24. Once complete flush CT String until clear water is observed, launch Cement Dart with 1,650 psi rating (purple colour) at pig launcher.
25. Pump and push cement dart to sit at the connector, record the volume. Once pumped 19.3 bbls of TIW (CT Volume: 20.3 bbls), slow down pump rate to 0.3 bpm to observe indication of pressure build up. (Once dart sit at connector, there will be increase in circulation pressure).
26. Apply and slowly increase pumping pressure, expected pumping pressure to burst the Cement Dart based on Dart Rating (1,650 psi).
27. Remove Cement Dart and make up new CT Connector. Repeat step 3.6 until 3.9 in CT Contingency #1.
28. Make up 2-1/8" DownJet Nozzle c/w 2.20" FC tool as per **BHA#2: 2-1/8" DownJet Nozzle c/w 2.20" Fluted Centralizer BHA** in **Appendix 1**.
    I. Take each BHA measurement and record in the DOR.
    II. Record length of BHA from CT Connector until end of nozzle.
29. Perform function test of the DownJet Nozzle to determine the pumping parameter and pressure of the tool. Record the data in the table below, do not exceed 5,000psi.

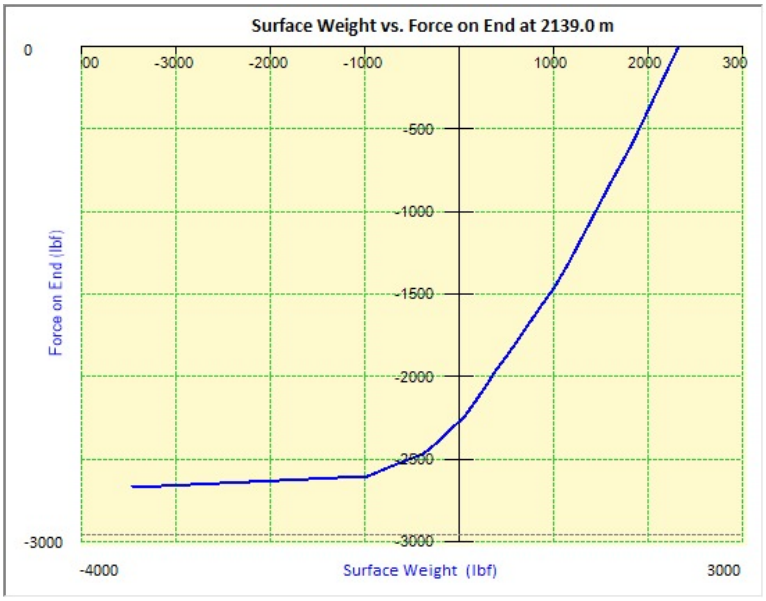
Flow rates (bpm)	Pressure (psi)	Remark
0.3		
0.5		
0.6		
0.7		
0.8		
0.9		
1.0		
1.1		
1.2		
1.3		

1.4		

30. Repeat step 6 till 12 in CT Contingency #1 prior making up BHA and open the well.
31. Start RIH while pumping TIW at idle rate until 2,129 m MDTHF (10m above CA Plug at 2,139 m MDTHF).
    31.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer **Appendix III**.
    31.2. Maximum coil speed RIH is **30-50 ft/min.**
    31.3. Closely observe weight indicator in control cabin while RIH.
    31.4. Conduct **pull test minimum of every 500 ft interval**, use CT Fatigue graph as reference. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.
    31.5. Slow down coil speed to 10 ft/min before and after passing through completion accessories.
    31.6. Observe return all the times. Flowback crew to monitor & record all return from time to time in Field Data Report.
    31.7. Do not exceed operating safety limits **5,000 psi.**
    31.8. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    31.9. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.
32. Once BHA reached at 2,128 m MDTHF (10m above CA Plug at 2,138 m MDTHF), 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

33. Continue RIH slowly until 2,138 m MDTHF (CA Plug) until a loss weight is observed. Do not slack off more -500 lbf at downhole (downhole force). Consult Weatherford Tool Specialist advice on maximum allowable setdown applied on the Widepak Plug). Tag twice to confirm the depth.
    33.1. Please refer below set down force graph for reference:



    33.2. Once confirmed, flag the CT on surface, as Flag#1 & reset depth counter & Orion depth to 2,138 m MDTHF as per well schematic.

Flag Number	Colour
Flag#1 (CA Plug)	

34. Pick up CT to depth 2,107 m MDTHF (Cement Retainer Setting Depth). Once confirmed, flag the CT on surface, as Flag#2. This will be setting depth for Cement Retainer.

Flag Number	Colour
Flag#2 (Cement Retainer)	

    34.1. Perform jetting across Cement Retainer Setting Depth 5 m above and below setting depth for 3 times.

35. POOH CT to surface & prepare for next run to set Cement Retainer at 2,107 m MDTHF and perform cementing.

CT RUN#2: SET CEMENT RETAINER AT 2,107 M MDTHF AND PERFORM CEMENTING

36. Make up 2.187" FH Cement Retainer tool as per **BHA#3: 2.187" Cement Retainer BHA** in **Appendix 1**.
    I. Ensure Weatherford Tool Specialist is available on site during the whole of CT Run #2
    II. Ensure that burst disk at Motor Head Assembly (MHA) is changed to 6,000 psi pressure rating. Record the burst disk rating in BHA checklist, witnessed and verify by WSS.
    III. Ensure 1/2" ball has been drifted through MHA, witnessed by WSS to confirm that it can pass through smoothly to the required ball seat in setting tool for Cement Retainer
    IV. Measure length of BHA & length from CT Connector to Packer Mid Element (COE) in ft.
    V. Ensure all BHA is properly torque according to Weatherford procedure.
    V. Ensure PCE stack is as APPENDIX II – CT STACK UP with quick test sub is in place.
    VI. Nipple up riser, pressure test quick test sub, pick up CT and tag the stripper and manipulate surface valve to the following position:

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

37. Start RIH to **2,097 m MDTHF (10 m above setting depth for Cement Retainer)** without pumping.
    37.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix II.
    37.2. Conduct pull test every 300m (1,000ft) or as deemed neccessary, use CT Fatigue graph as reference. **While perform pull test, pump 1 bbls of TIW at 0.3 bpm**. Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.
    37.3. Maximum coil speed RIH is **30-40 ft/min.**
    37.4. Slow down coil speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
    37.5. Closely observe weight indicator in control cabin while RIH.
    37.6. Record all parameter & return all the times.
    37.7. Do not exceed operating safety limits **5,000 psi.**
    37.8. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    37.9. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the Coiled Tubing at specified speed.
    37.10. Do not snub more than -1,000 lbf (downhole force). If encounter snub force, inform WSS.

38. Once CT reach at **2,097 m MDTHF (10 m above setting depth)**, stop coil and conduct pull test of 10m/30ft without pumping and record the pulling weight both static and dynamic (IMPORTANT).

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

39. Continue RIH slowly at 10ft/min to **2,112 m MDTHF (5m below setting depth).** 5m below previous Flag #2 in previous CT Run. (DO NOT ATTEMPT TO RIH FURTHER UNTIL FLAG#1 & TAG CA PLUG).

40. Pick up & tension CT to **2,107 m MDTHF (Cement Retainer Setting Depth) with reference of previous Flag#2**. Corrected depth TBC during measurement at site. Once get approval from town on the setting depth, perform the following step to set the Cement Retainer:

40.1. Record the CT pressure and close plug valve in the reel.

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

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

41. At depth **2,107 m MDTHF setting depth**, launch ½" ball to set Cement Retainer. Follow instruction from Weatherford Tool Specialist.

41.1. Pump **TSW** at 1 bpm to chase the ball over gooseneck.

41.2. Once the ball has pass through the gooseneck, shutdown the pump and allow the ball to gravitate to seat (approximately 30 minutes).

41.3. When the ball is seated, a pressure build up will be observed.

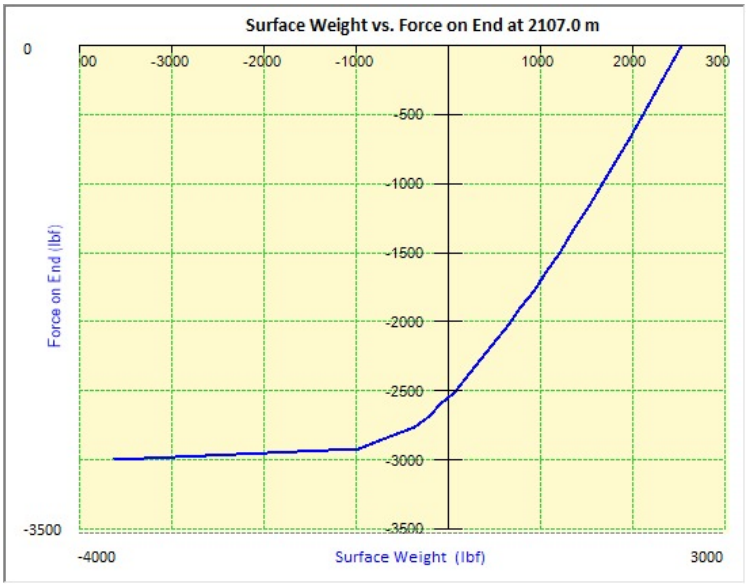
41.3.1. Slowly pressure CT workstring to establish a 1,000psi (1,500psi max) differential pressure inside the tubing "at the tool" to begin the setting sequence.

41.3.2. Continue pressuring CT workstring to establish a 2,000psi (2,500 psi max) differential pressure inside the tubing "at the tool" to anchor the cement retainer against the tubing wall. Hold pressure for 5 minutes.

41.3.3. Continue pressuring CT workstring to establish a 2,500 psi (3,000 psi max) differential pressure inside the tubing "at the tool" to complete the set.

41.3.4. Continue pressure CT workstring to 3,000 psi (3,500psi max) differential pressure inside the tubing "at the tool" to unlock ball seat and close circulation ports (monitor indication for pressure bleed off on its own).

41.4. Once the Cement Retainer is set, apply set down weight -1,000 lbf (downhole force) to confirm CR is fully set.



42. Fill up CT annulus, long string & PCP at 0.5 bpm (497 bbls of **TIW**). Once observe liquid return at surface, perform integrity test on cement retainer by applying 500 psi on to the annulus side of CT. Monitor & record pressure for 1 hour at CT Annulus / WHP, THP at LS & PCP for every 5 minutes interval.

42.1. If no liquid return at surface / observe pressure build up at CT Annulus, increase pumping rate to 1.0 bpm to continue fill up. Finalize with an approval from WSS and EIC at town.

43. Perform injectivity test with **TSW** by pumping through CT and monitor the rate and pumping pressure:

Note: To apply 300 psi on CT Annulus by pressure up with Graco pump & maintain pressure during injectivity test & cementing.

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbls)	THP (psi) SS	THP (psi) LS	PCP (psi)
0.30						
0.50						
0.70						
0.90						
1.00						
1.10						
1.20						

43.1. Report the injectivity test result to WSS and EIC at town.

43.2. Closely monitor the CT Annulus Pressure/WHP, THP long string & PCP for any changes.

43.3. Record all parameter for every 5 minutes interval.

43.4. Stop pump when CT pressure (Circulating Pressure) exceeding 4,500 psi. Cement Retainer rating is 5,000 psi.

44. After completed pumping, share injectivity test operating parameters with town before proceeding with next step.

45. Conduct job specific meeting between technical support team (base/office) and operation team (offshore).

46. Proceed to mix 35 bbls of 15.0 ppg cement in one BMX Tank and 30 bbls of Contaminated Gel in another BMX Tank as per below while continue pumping **Sea Water** through CT at idle rate.

46.1. Precaution and standard practice during mixing cement:

46.1.1. Make sure to well-stir the liquid additives especially for BA-58L, R-21LS & ASA-304L

46.1.2. To follow the mixing sequence

46.1.3. Make sure mix fluid homogenous before cut cement sack. take mix fluid sample (recommend 5 liter)

46.1.4. Record time once 1st cement sack dump into BMX. Cement transfer should be not more than cut-off time (3 hr as per lab report/program)

46.1.5. Check the density (min 2 times each sampling), gradually taken before the last sacks pallet. Stop adding cement once reaching 15ppg +- 0.2ppg.

46.1.6. Take 4 cement samples - to put inside water bath at 190F & surface temperature.

Contaminated Gel				420	gals	10	bbls	Description
Seq	Product	Concentration		Volume				
1	Sea Water	944	gptg	397	gals	9.4	bbls	Base Fluid
2	SCR	50	gptg	21	gals	0.5	bbls	Cement retarder
3	Gel	41	pptg	17	lbs			Gelling agent

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

15 ppg Cement			1470	gals	35	bbls
Products	**Concentration**		**Volume**			
Sea Water	4.913	gps	707.84	gals	16.85	bbl
FP-32L (Defoamer)	0.05	gps	7.16	gals	0.17	bbl
ASA-304L (Anti Settling Agent)	0.022	gps	3.15	gals	0.08	bbl
BA-58L (Bonding Agent)	0.55	gps	78.81	gals	1.88	bbl
FL-70L (Fluid Loss Agent)	0.45	gps	64.48	gals	1.54	bbl
CD-38L (Dispersant)	0.12	gps	17.19	gals	0.41	bbl
R-21LS (Retarder)	0.13	gps	18.63	gals	0.44	bbl
EC-4 (Expanding Agent)	1.0%	bwob	124.5	lbs	2.3	55 lbs per sacks
Blended Slagment with 12.25% Silica	0.1225	cuft/sk	13,972.33	lbs	254.0	55 lbs per sacks

1. Fill up batch mixer with sea water
2. Add additives as per above sequence
3. Note the time when 1st cement sack is added into mixed water mixture. Thickening time starts once 1st cement sacks is added into mixed
4. Refer to Appendix 5 for cement lab test results

Note:

1. **Record and inform Engineer in Charge when the first sack of cement is added to mixed water mixture.**
2. **Cement Thickening Time is 16 hours 18 minutes from first sack of cement added.**
3. **Cement Mixing Time is 2 hours and additional safety margin 1 hour.**
4. **Total Cement Mixing Cut-Off Time is 3 hours.**
5. **After complete mixing, take cement sample from Batch Mixer and CT Reel Manifold and keep sample for monitoring. Label sample properly.**

47. Upon complete mixing and density witness and confirmation of WSS, begin to pump cement according to the following steps:

    47.1. Take sample at surface, put into two conditions, one at surface temperature and another sample in water bath at max temperature.

    47.2. Open overboard valve and displace surface lines to cement slurry.

    47.3. Reset data acquisition before start pumping.

    47.4. Close overboard valve and equalize pressure across reel valve.

    47.5. Ensure wellhead valves are configured according to table below: -

Valve	Position
Reel Manifold	OPEN
Flow Cross Return Valve (Cetco lines) - Graco pump is tap in in between isolation valve to pressure up / maintain WHP at 300 psi during injectivity test & cementing	OPEN
Wing Valve	CLOSE

    47.6. tart pumping according to pumping sequence specified below (CT Volume 20.3 bbls), maximum pumping rate subject to circulating pressure, based on Weatherford Cement Retainer pressure rating is 5,000 psi. Do not exceed 4,500 psi:

    Note: To apply 300 psi on CT Annulus by pressure up with Graco pump & maintain pressure during injectivity test & cementing. Record initial parameter (WHP, THP long string & PCP). Keep monitor & record WHP, THP long string & PCP every 5 minutes interval during cementing.

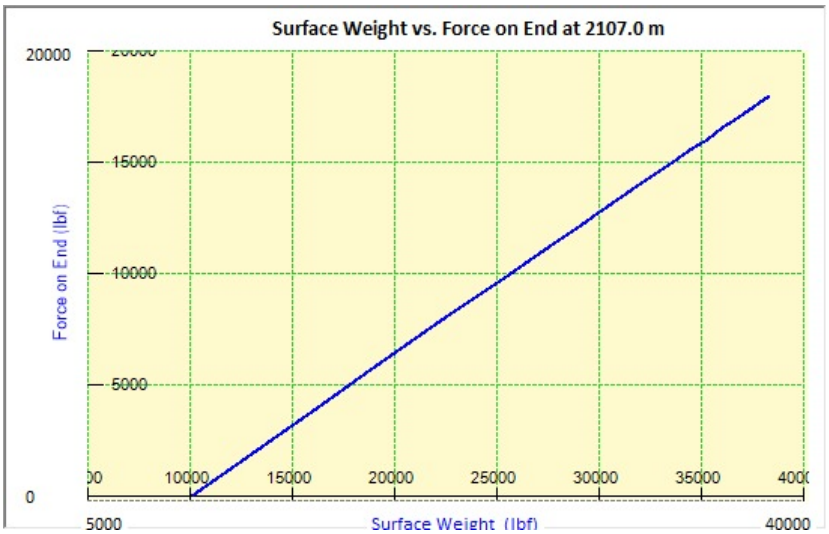
#	Start Depth (ft)	End Depth (ft)	Fluid at Reel Manifold	Fluid Entry Volume (bbl)	Total Fluid Pumped (bbl)	Pump Rate (bpm)	CT Speed (ft/min)	Fluid at Nozzle	Valves Config. Flow Tee	Remarks
1	6,913	6,913	SW	5	5	0.5	-	SW	*Open Return *Open injection	Reset DAS Volume
2	6,913	6,913	Install lead cement dart (3,000 psi cement dart rating), **Green color**							
3	6,913	6,913	Cement	20.3	20.3	0.3 – 1.0	-	SW	*Open Return *Open injection	Reduce pump rate to 0.3 bpm once 19.3 bbls is pumped until lead dart land at connector. Cement at tip of nozzle.
4	6,913	6,913	Once observe circulation pressure increase, apply at least +/-1,200 psi pumping pressure to burst the lead Cement Dart							
5	6,913	6,913	Cement	6.7	27	0.3 – 1.0	-	Cement	*Open Return *Open injection	Cement at tip of nozzle
6	6,913	6,913	Install tail cement dart (1,650 psi cement dart rating), **Purple color**							
7	6,913	6,913	SW	20.3	47.3	0.3 – 1.0	-	SW	*Open Return *Open injection	Reduce pump rate to 0.3 bpm once19.3 bbls is pumped until tail dart land at connector. All 27 bbls cement outside of nozzle.
8	6,913	6,910	Once Observe circulation pressure increase, Stop pumping. Sting out from cement retainer (Follow as per Weatherford's procedure)							
9	6,910	6,910	Stop Graco pump. Close plug valves on injection line. Open Flow cross return valve, apply at least +/-1,200 psi pumping pressure to burst the tail Cement Dart							
10	6,910	6,910	Contaminated Gel	5	52.3	0.5	0	SW	*Open Return *Close injection	-
11	6,910	6,910	SW	15.3	67.6	0.5	0	Contaminated Gel	*Open Return *Close injection	Contaminated gel at Nozzle.
12	6,910	6,050	SW	5	72.6	0.3	-52	SW	*Open Return *Close injection	Spot Contaminated gel, 5 bbls

13	6,050	5,950	SW	10	82.6	Max Rate	-10	SW	*Open Return *Close injection	Pick-up CT 100 ft above top of Contaminated Gel
14	5,950	6,883	SW	20.3	102.9	Max Rate	45	SW	*Open Return *Close injection	RIH back to 30 ft above top of CR
15	6,883	6,883	Contaminated Gel	10	112.9	Max Rate	-	SW	*Open Return *Close injection	Circulate out excess cement in Coil and Tubing. Reciprocate CT during circulate gel.
16	6,883	6,883	SW	80	192.9	Max Rate	-	SW	*Open Return *Close injection	**Bottom Up until at least 2x tubing volume or clear return**. Reciprocate CT during bottoms up.
17	6,883	6,883	Contaminated Gel	10	202.9	1.0	-	SW	*Open Return *Close injection	Fill up CT with Gel
18	6,883	6,883	SW	10.8	213.7	1.0	-	Contaminated Gel	*Open Return *Close injection	Fill up CT with SW and displace 0.5 gel out of nozzle
19	6,883	5,155	SW	10	223.7	0.3	-52	SW	*Open Return *Close injection	POOH CT while spot gel.
20	5,155	0	SW	-	-	Max Rate	-30	SW	*Open Return *Close injection	Continue POOH to surface

1. Actual CT string volume will be confirmed during rig up.
2. (-) refers to CT moving upward / pick up coil
3. During Pumping cement and displacement fluid, Field Engineer / Cementer / WSS / CT Supv to verify and witness the fluid level inside batch mixer.
4. In the event PCP/ CT Annulus pressure increase during pumping cement, proceed to **step 49**.
5. **DO NOT EXCEED** pumping pressure of 5,000 psi during cementing stage (CR rating is 5,000 psi).

48. Once all treatment volume pumped, apply an overpull of 2,000 pounds (downhole force) over tubing weight to sting out from cement retainer.

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



48.2. Record the pulling weight both static and dynamic.

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

49. In the event PCP / CT Annulus pressure increase during cementing operation (cement still left in CT), proceed step below:

    49.1. Immediately stop pumping, sting out CT from Cement Retainer as per Weatherford's procedure.

    49.2. Stop Graco pump. Close plug valves at injection line leading to flow tee. Open return line & pick up CT to 10 ft above Cement Retainer depth.

    49.3. Circulate out all excess cement at maximum pumping rate by pumping 5 bbls of Contaminated Gel followed by 80 bbls of Sea Water (2x tubing volume) or until clear return at surface.

    49.4. Spot 10 bbls of Contaminated Gel at 0.3 bpm on top of Cement Retainer while pick up CT to 5,176 ft MDTHF at – 52 ft/min.

    49.5. Proceed to POOH CT to surface while pumping TIW at maximum rate without exceeding MASTP of 850 psi.

50. Proceed POOH CT to surface (follow step 47.6):

    50.1. Maximum coil speed while POOH is 50ft/min.

    50.2. Slow down coil speed to 10ft/min 50ft before and after passing through completion accessories.

    50.3. Do not exceed CT operating limit (refer to Appendix Section: TFA simulation)

51. Once CT reaches at surface:

    51.1. Close master and swab valve.

    51.2. Flush pumping line, CT and BHA with TIW to clean excess cement.

    51.3. Service all BHA & fluid end of pumping unit and prepare for next run.

52. Wait on cement to **completely harden after 24 hours from 1st cement sack added.**

CT RUN#3: POST CEMENTING CLEANOUT UNTIL TOP OF CEMENT RETAINER AT 2,107 M MDTHF

53. Make up 2-1/8" SpinCat Nozzle tool as per **BHA#4: 2-1/8" SpinCat Nozzle BHA** in **Appendix 1**.

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

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

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

55. Repeat step 6 till 12 in CT Contingency #1 prior making up BHA and open the well.
56. Start RIH BHA while pumping TIW at 0.3bpm until 1,561 m MDTHF.
    - 56.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer **Appendix III**.
    - 56.2. Maximum coil speed RIH is **30-50 ft/min.**
    - 56.3. Closely observe weight indicator in control cabin while RIH.
    - 56.4. Conduct pull test minimum of every 300m (1,000ft) interval, use CT Fatigue graph as reference. Record RIH, Hanging and POOH weight in treatment report.
    - 56.5. Slow down coil speed to 10 ft/min before and after passing through completion accessories.
    - 56.6. Observe return all the times. Flowback crew to monitor & record all return from time to time in Field Data Report.
    - 56.7. Do not exceed operating safety limits **5,000 psi.**
    - 56.8. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    - 56.9. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.
57. Once BHA reaches 1,561 m MDTHF (10m above contaminated Gel), 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. (If encounter early HUD, Pick-up BHA and record the weight parameter)

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

58. Establish return first by pumping at 1.1 bpm prior to penetrate by pumping 40 bbls of TIW or until return is established.

Notes:

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

59. Continue RIH at 10 ft/min while pumping TIW at 1.1 bpm starting at depth 1,840 m MDTHF until 2,112 m MDTHF (Cement Retainer).

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

No.	Stage	Fluid	Liquid Rate	Total Liquid	N2 Rate (if require)	CT Speed	Duration	Depth	Remarks
			BPM	BBL	SCF/M	ft/min	Minute	m	
1	CT at 10m above HUD	TIW	1.0	0.0	300	0	0	10m above HUD (1,561 m MDTHF)	Establish return on surface
2	RIH to HUD and Penetrate HUD/Fill	TIW	1.0	10.0	300	10	30	HUD + 30m	Monitor return & CT weight on surface
3	Circulate	D801 Gel	1.0	5.0	300	0	5	Stationary CT	Provide suspension to the fill and lift to surface
Wiper Trip 10m above previous HUD									
4	RIH to last HUD and Penetrate HUD/Fill	TIW	1.0	10.0	300	10	10	HUD + 30m	Monitor return & CT weight on surface
5	Circulate	D801 Gel	1.0	5.0	300	0	5	Stationary CT	Provide suspension to

									the fill and lift to surface
Wiper Trip 10m above previous HUD and repeat step 1-5 until Cement Retainer at 2,107 m MDTHF, Flag CT at surface									
6	Hole Cleaning (Circulate)	D801 Gel	1.0	20	300	0	20	Stationary CT at 2,104 m MDTHF	Hole cleaning stage. 1.0x CT/Tubing Annulus Volume
7	Bottoms Up (Circulate)	TIW	1.0	300	300	0	300	Stationary CT at 2,104 m MDTHF	Hole Cleaning stage. As per Circa Simulation
Once completed CBU, wiper trip to depth 1,207 m MDTHF at 10 ft/min									
8	POOH	TIW	0.3	72	300	30	240	To Surface	Monitor return on surface

60. If CT encountered hard obstruction, consult town for further instruction.

61. Once CT reach 2,107 m MDTHF (Cement Retainer), pick up 3m from top of CR, circulate 20 bbls of Gel and perform bottoms up with TIW at 1.1 bpm for 5 hours at depth 2,104 m MDTHF as per CIRCA Simulation. Flag #1 CT at surface at depth 2,107 m MDTHF (Cement Retainer).

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

Flag Number	***Colour***
Flag#1	

62. Wiper trip to depth to 1,207 m MDTHF while pumping TIW at 1.1 bpm while pick up CT at 10 ft/min.

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

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

APPENDIX I – BHA SCHEMATIC

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

DIMENSION BID

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

Client	Petronas Carigali	Well	D-06S
Field	Dulang D	Min Restriction	2.25"
Job Type	Zone Shut Off	BHP	
Job No.		BHT	224 F

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

BHA LENGTH	12.30
MAXIMUM OD	2.13
MINIMUM ID	

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

ADDITIONAL INFORMATION:

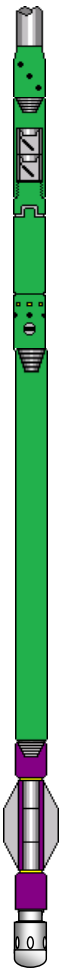
Ensure to measure length and OD of each BHA tool before makeup.

BHA#2: 2-1/8" DOWNJET NOZZLE C/W 2.20 FC BHA

DIMENSION BID

BHA DIAGRAM #2 - 2-1/8" DownJET Nozzle c/w 2.20" Fluted Centralizer BHA

Client	Petronas Carigali	Well	D-06S
Field	Dulang D	Min Restriction	2.25"
Job Type	Zone Shut Off	BHP	
Job No.		BHT	224 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**External Dimple CT**	1.5" CT	1.5" AMMT PIN		2.125	0.6	0.6
	MHA Disconnect drop ball 3/4" Shear pressure 5,636 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5000 psi	1.5" AMMT BOX	1.5" AMMT PIN		2.125	2.5	3.1
	5 FT Straight Bar	1.5" AMMT BOX	1.5" AMMT PIN		2.125	5.0	8.1
	Crossover	1.5" AMMT BOX	1.0" AMMT PIN		2.125	0.5	8.6
	2.20" Fluted Centralizer	1.0" AMMT BOX	1.0" AMMT PIN		2.200	1.0	9.6
	Crossover	1.0" AMMT BOX	1.5" AMMT PIN		2.125	0.5	10.1
	2-1/8" DownJet Nozzle	1.5" AMMT BOX			2.125	0.8	10.9

BHA LENGTH	10.90
MAXIMUM OD	2.20
MINIMUM ID	

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

ADDITIONAL INFORMATION:

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

BHA#3: 2.187" FH CEMENT RETAINER BHA

DIMENSION BID

BHA DIAGRAM #3- 2.187" FH Cement Retainer

Client	Petronas Carigali	Well	D-06S
Field	Dulang D	Min Restriction	2.25"
Job Type	Zone Shut Off	BHP	
Job No.		BHT	224 F

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	**External Dimple CT Connector**	1.5" CT	1.5" AMMT PIN		2.125	1.1	1.1
	2 -1/8" MHA Disconnect drop ball 0.75" Shear pressure 2 pin 2,000 psi Circulating drop ball 0.63" Shear pressure 2 pin 2,000 psi Burst Disc 6,000 psi	1.5" AMMT BOX	1.5" AMMT PIN		2.125	1.9	3.0
	FH Setting Tool Drop ball : 1/2"	1.5" AMMT BOX	ACME		2.125	4.45	7.4
	Setting Sleeve	ACME	ACME		2.187	1.03	8.43
	FH Cement Retainer COE from top of CT Connector: 8.82 ft (To verify measurement onsite) Setting pressure 3,500 psi Overpull to release 2,000 lbf	ACME			2.187	1.45	9.88

BHA LENGTH	9.88
MAXIMUM OD	2.187
MINIMUM ID	

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

ADDITIONAL INFORMATION:

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

BHA#4: 2-1/8" SPINCAT NOZZLE BHA

DIMENSION BID

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

Client	Petronas Carigali	Well	D-06S
Field	Dulang D	Min Restriction	2.25"
Job Type	Zone Shut Off	BHP	
Job No.		BHT	224 F

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

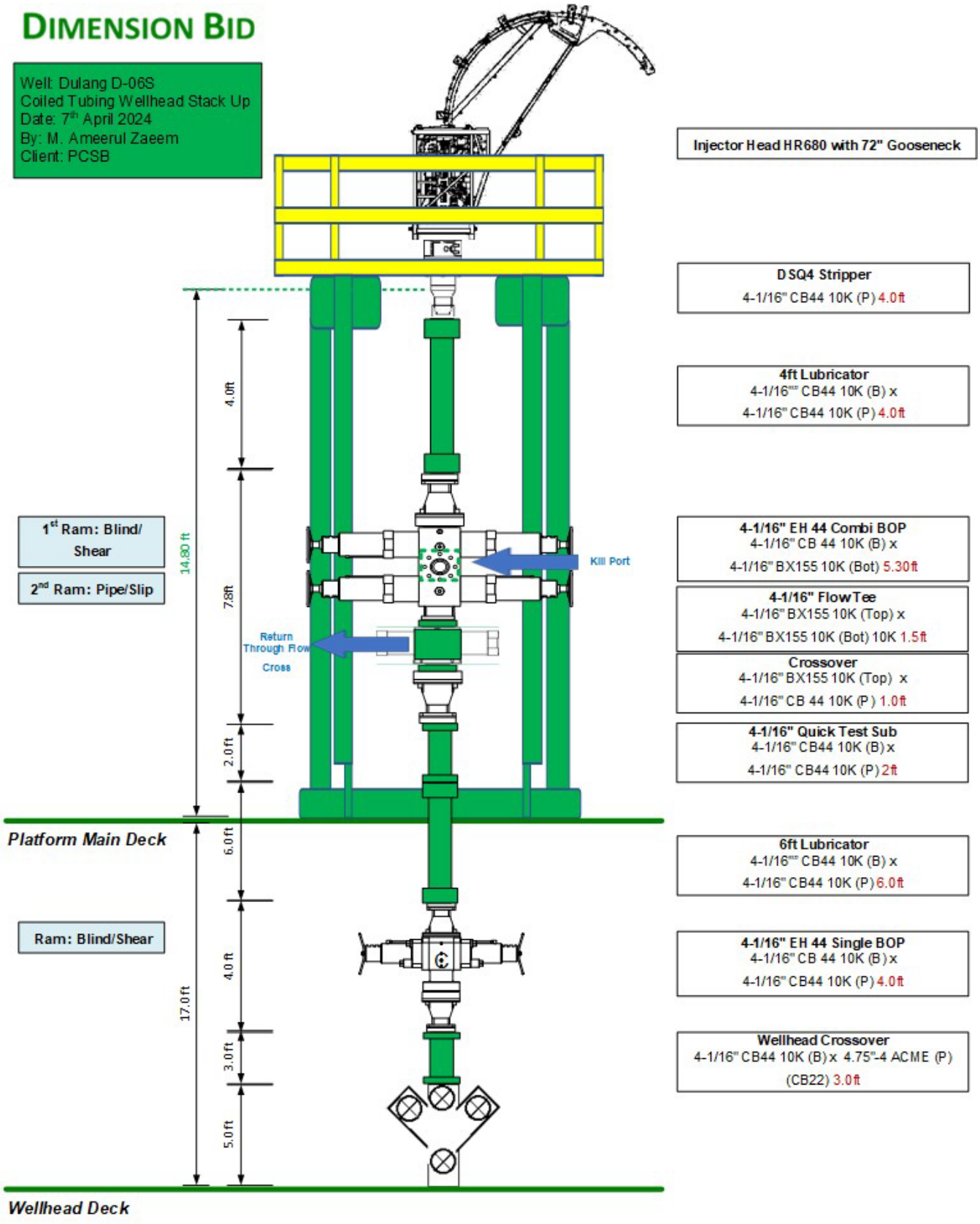
BHA LENGTH	12.30
MAXIMUM OD	2.13
MINIMUM ID	

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

ADDITIONAL INFORMATION:

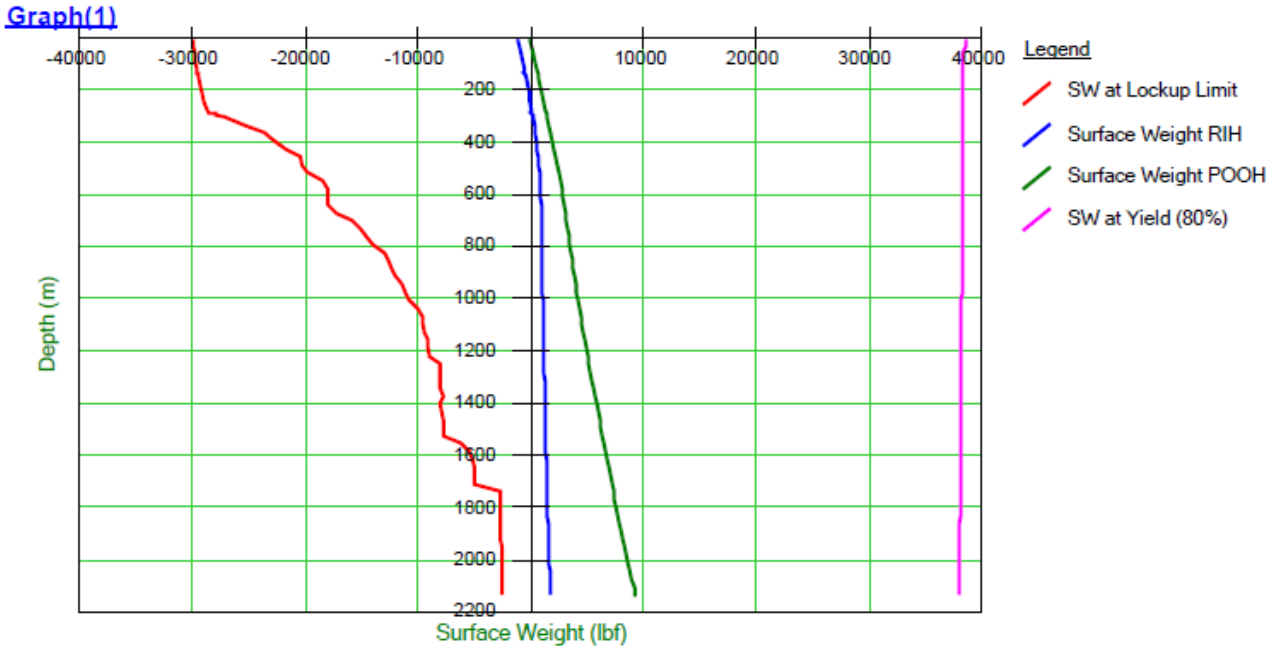
Ensure to measure length and OD of each BHA tool before makeup.

APPENDIX II – CT STACK UP

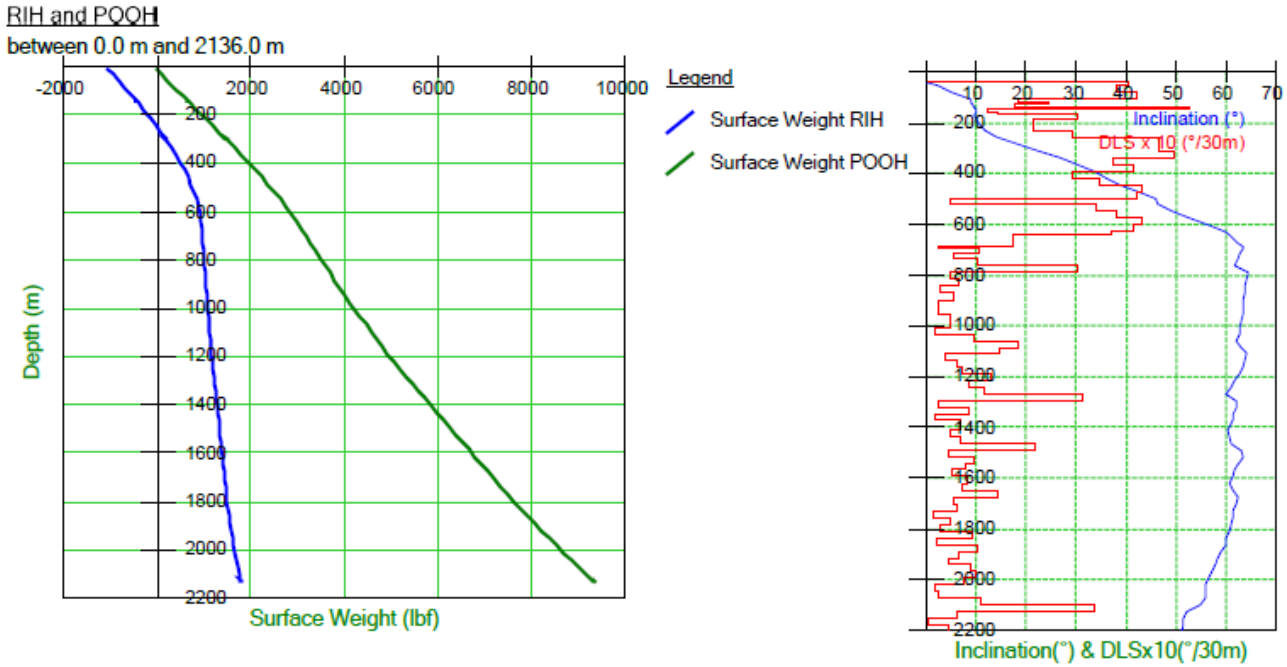


APPENDIX III – ORPHEUS SIMULATIONS

TUBING FORCE ANALYSIS AT 2,136 M MDTHF

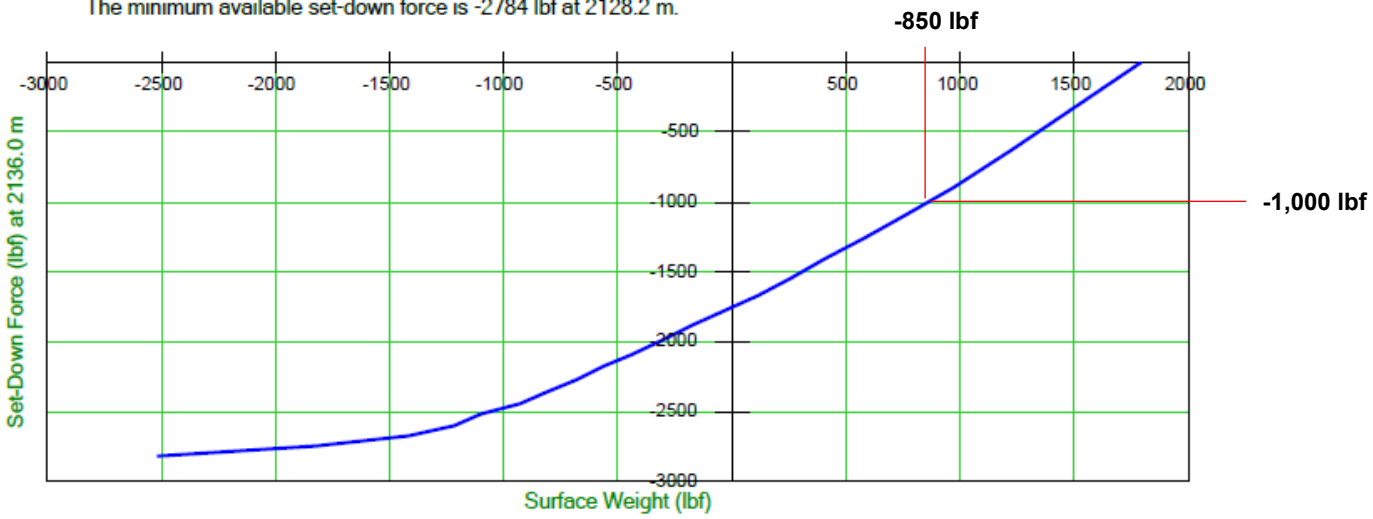


RIH & POOH WEIGHT



MAXIMUM STRING SET DOWN LIMIT

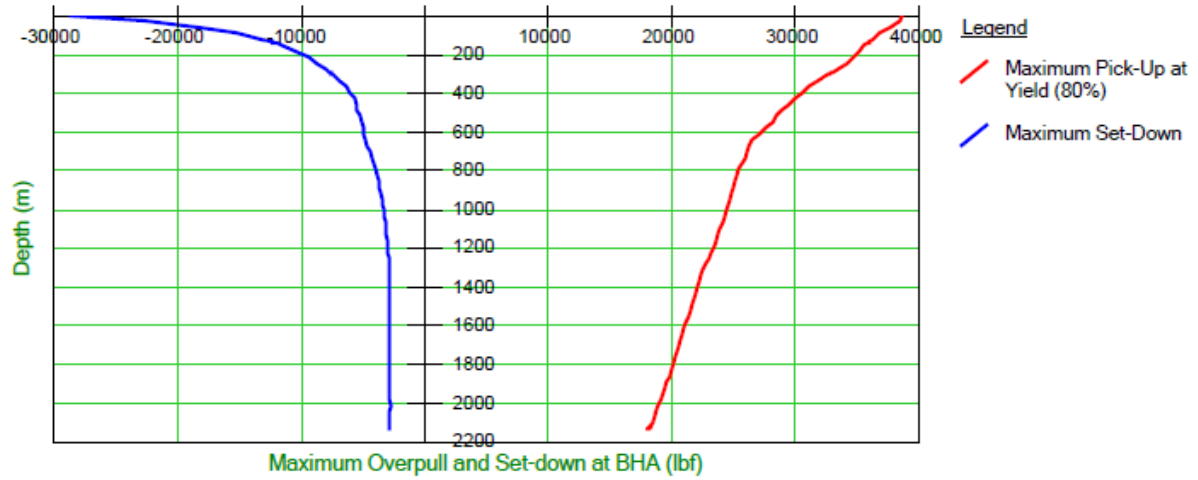
MD3 The available set-down force at 2136.0 m is -2816 lbf at the end of the string.
The weight indicator reading will be -2518 lbf on surface.
The minimum available set-down force is -2784 lbf at 2128.2 m.



MAXIMUM STRING PICK UP LIMIT

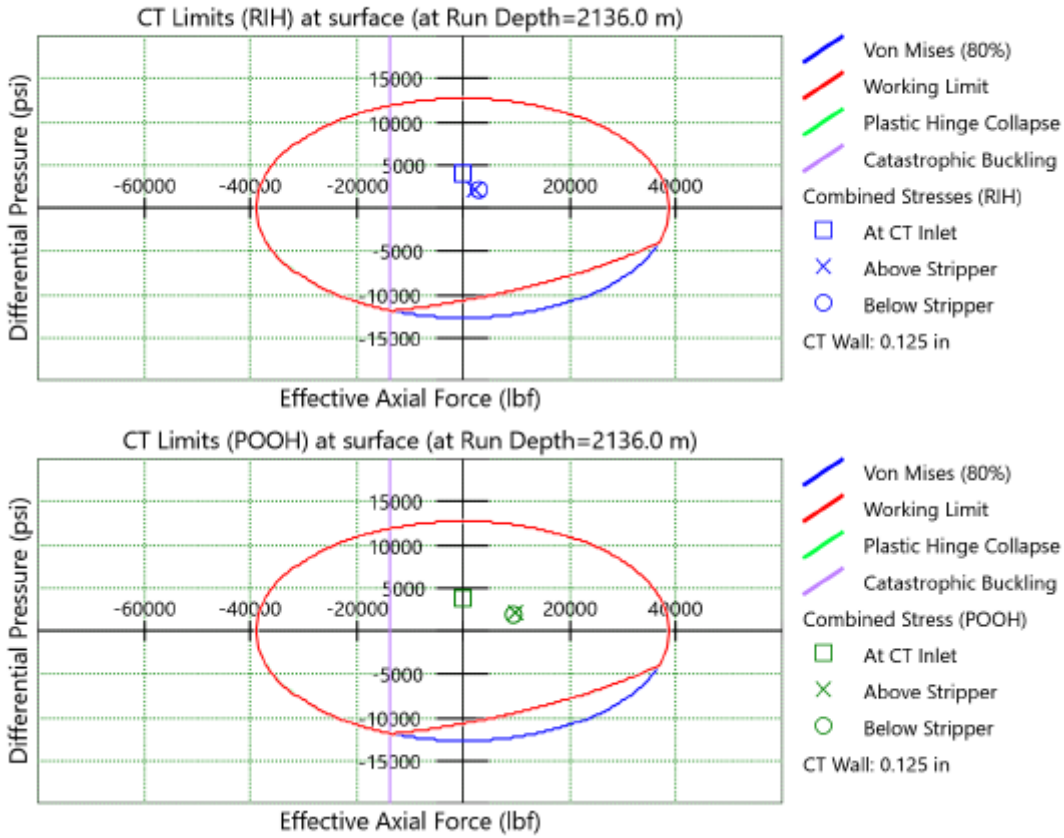
Calculations at 2136.0 m

MD1 The available pick-up at 2136.0 m based on 80% of yield strength is 18037 lbf.
The weight indicator reading will then be 37995 lbf.



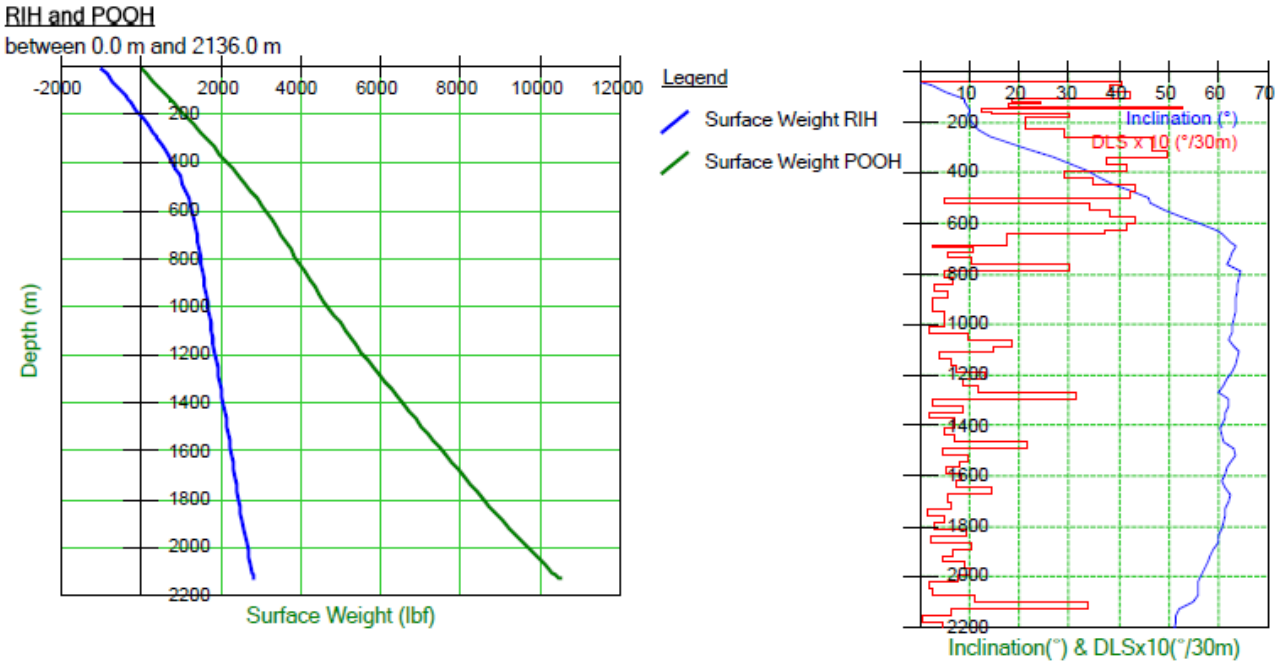
STRING LIMIT

CT Limits

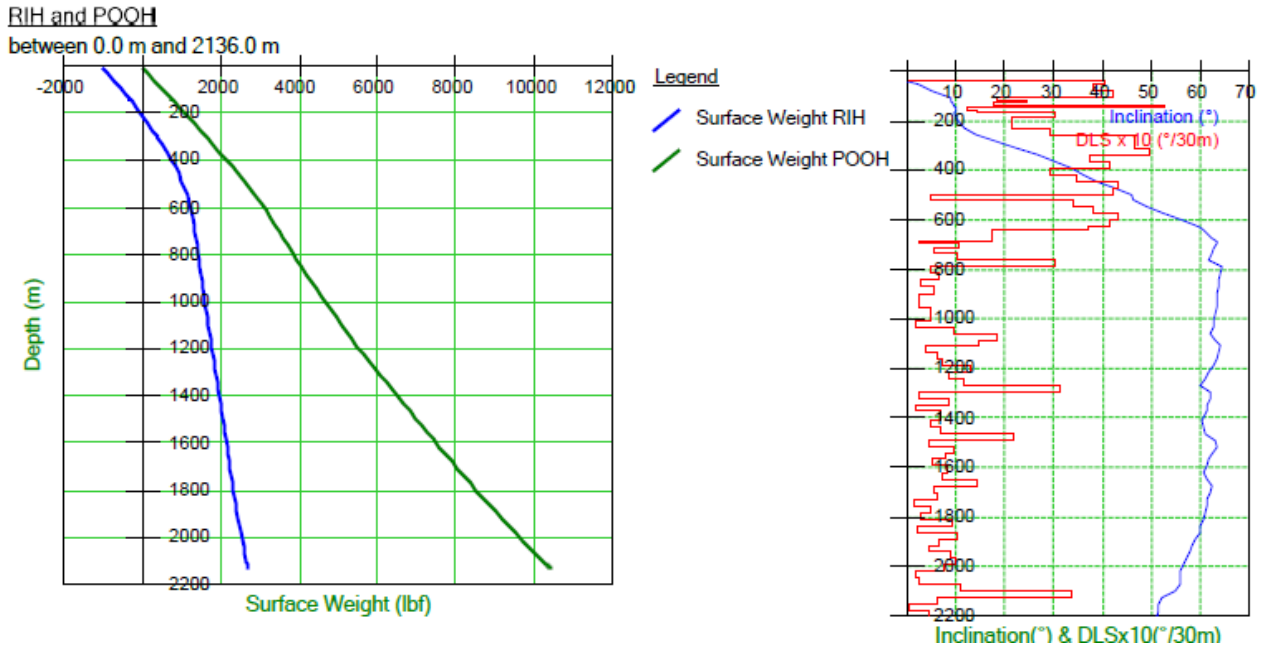


SENSITIVY ANALYSIS TFA

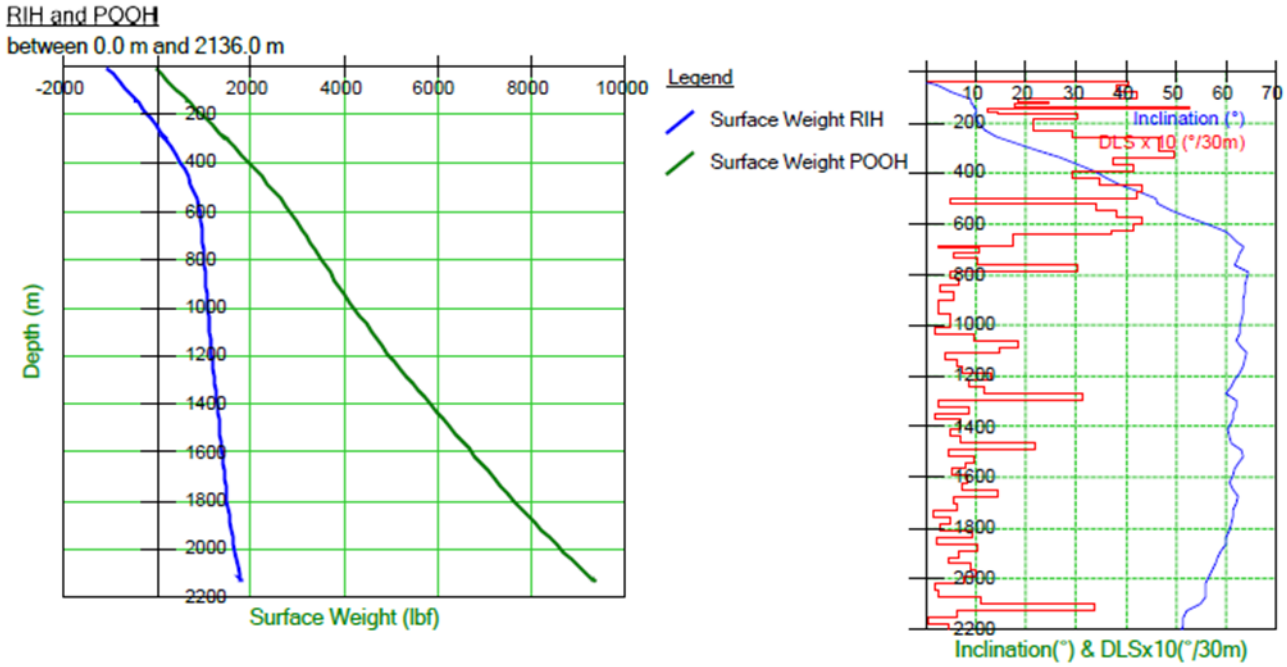
Without Pumping (0 bpm)



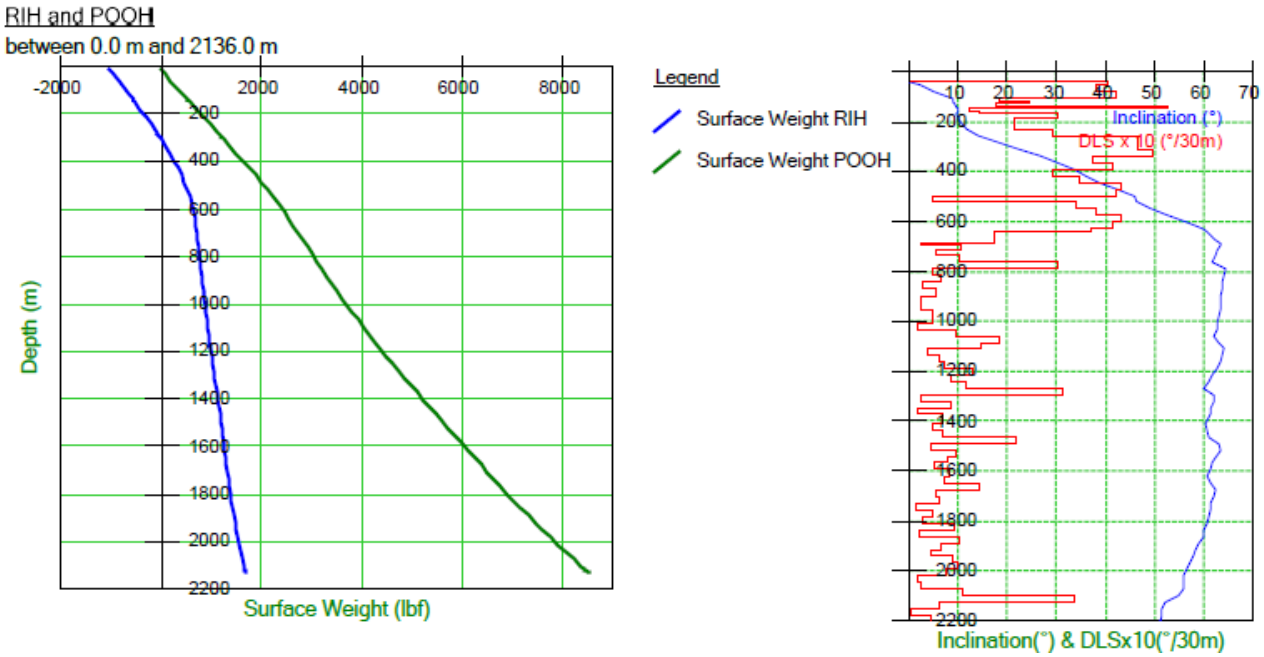
Idle Rate (0.3 bpm)



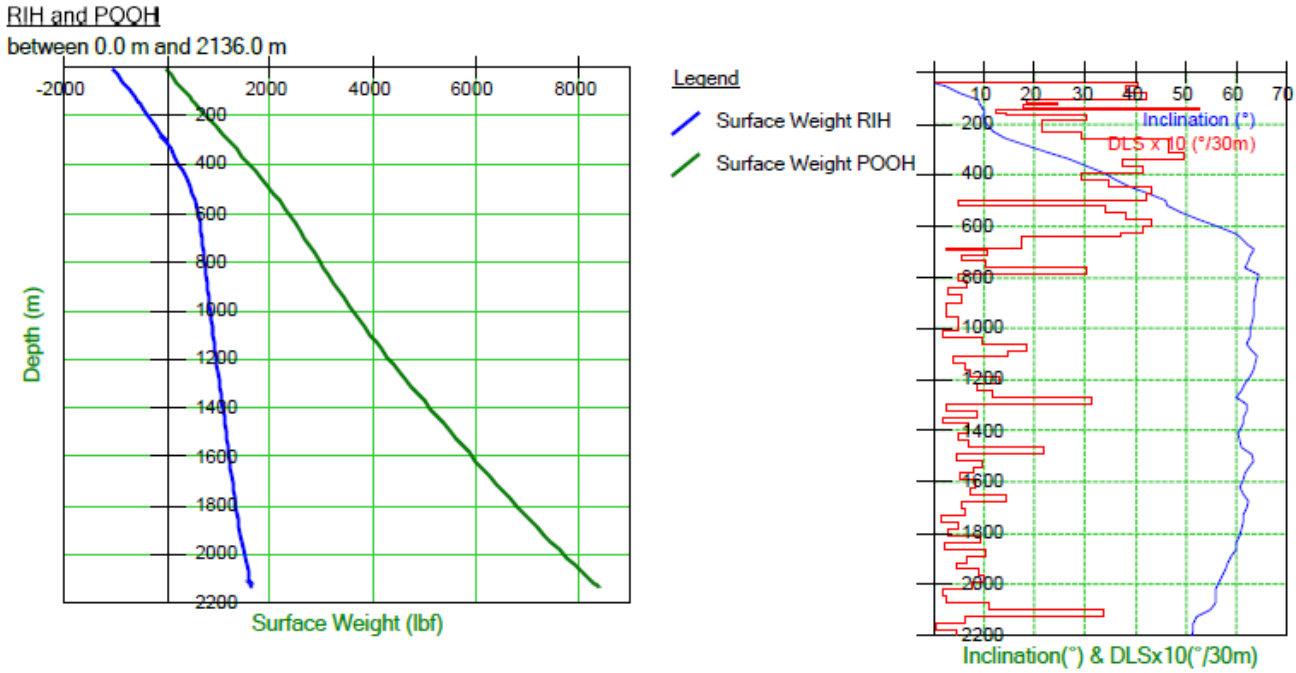
High Rate (1.1 bpm)



Nitrified (0.9 bpm 300 scf)

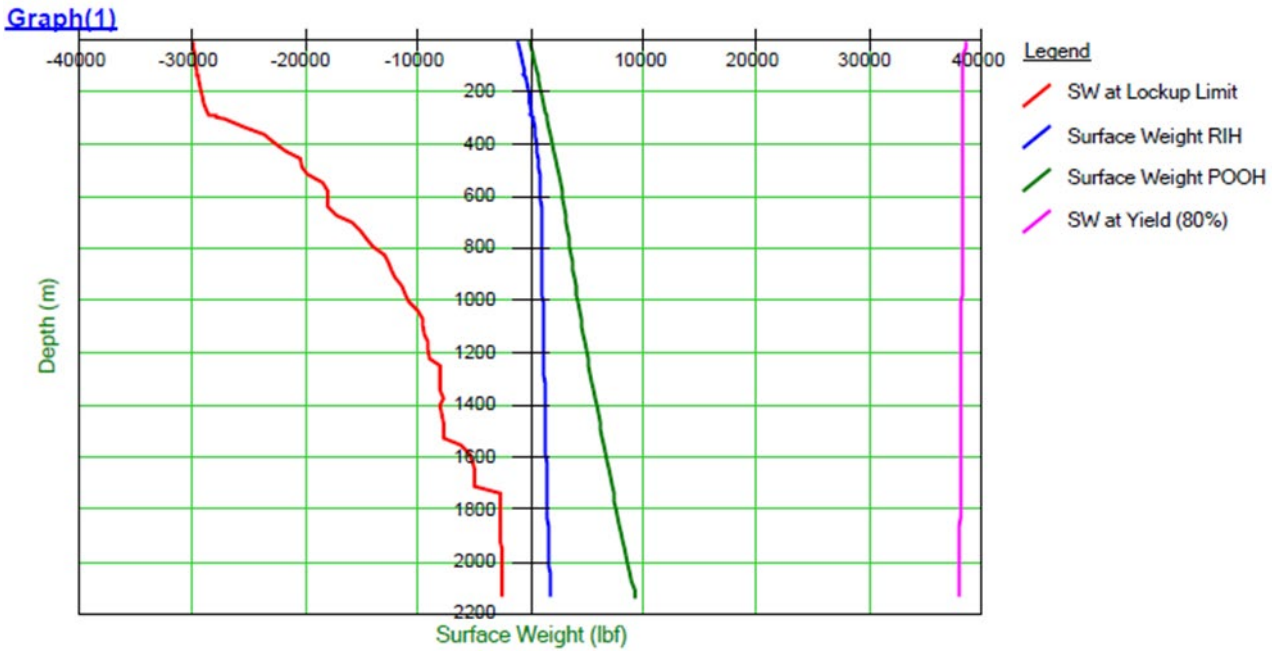


Nitrified (0.9 bpm 400 scf)

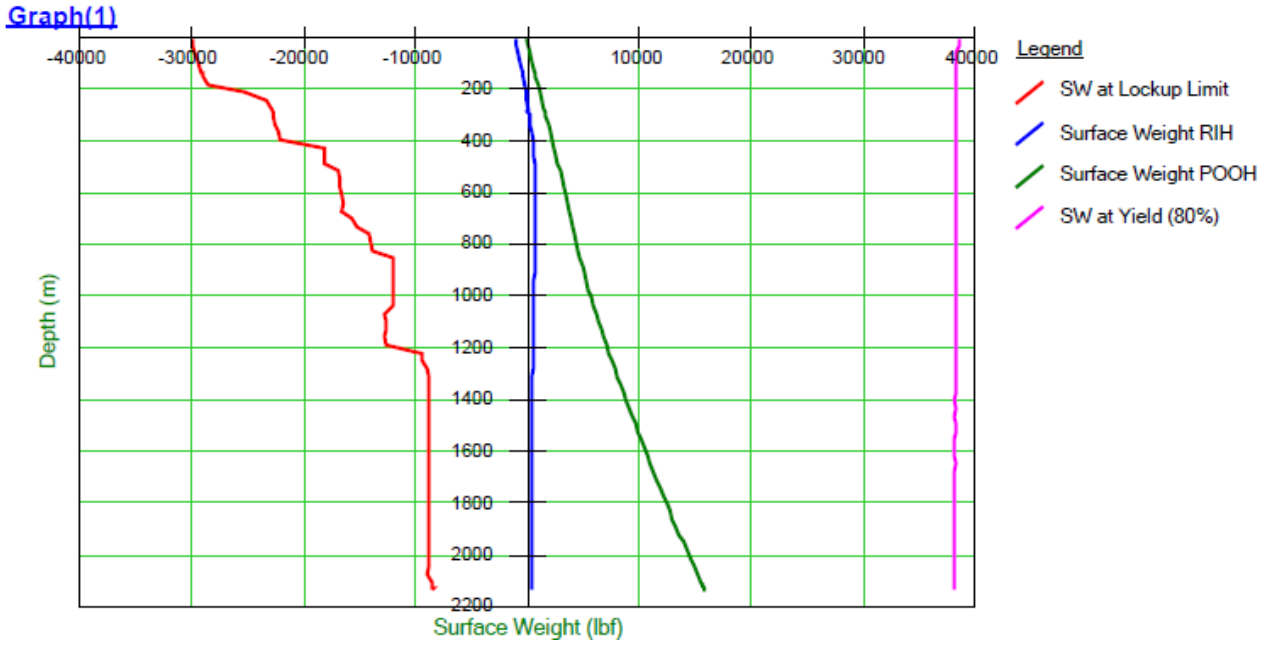


SENSITIVY ANALYSIS FRICTION FACTOR

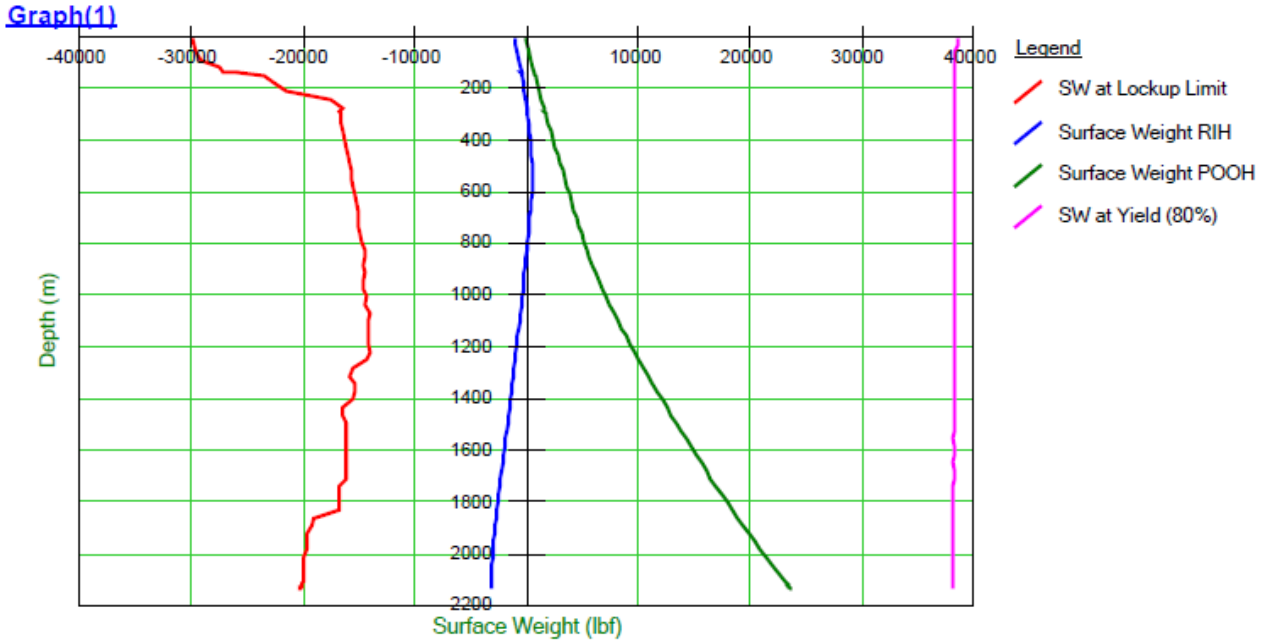
Friction Factor 0.3 (Default Value)



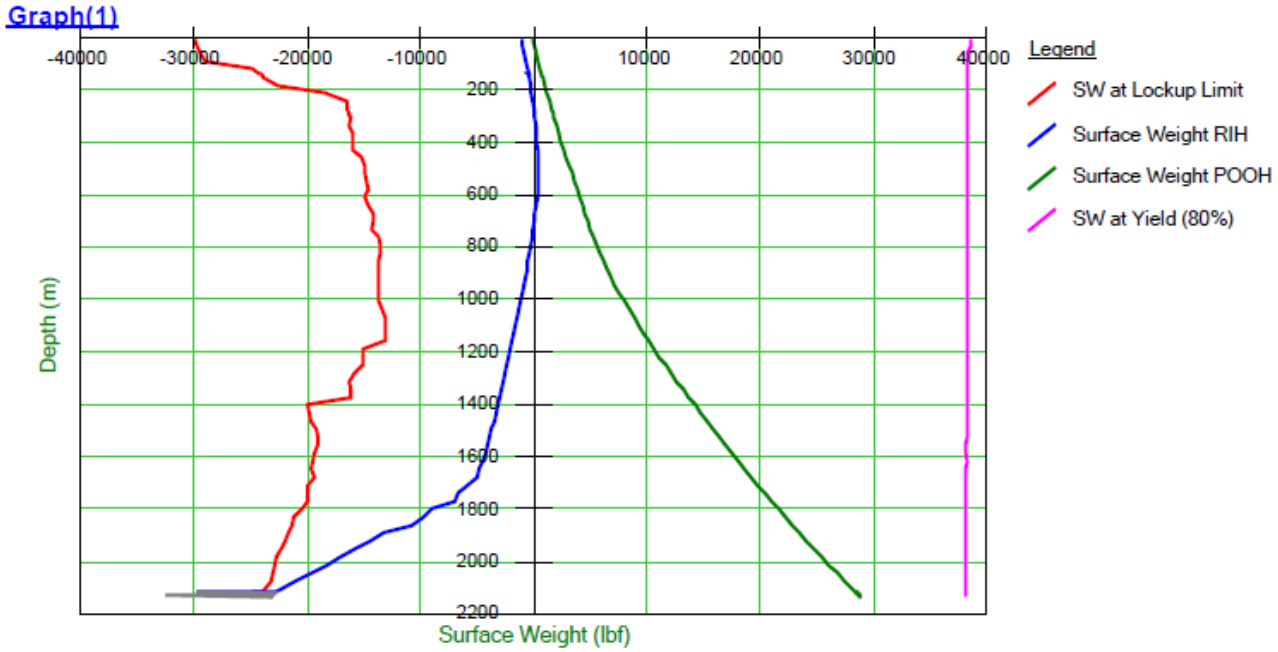
Friction Factor 0.5



Friction Factor 0.7



Friction Factor 0.8 (Lock up detected at depth 1,913m MDTHF)



SUMMARY OF TUBING FORCE ANALYSIS AT DEPTH 2,136 M MDTHF (NIPPLELESS PLUG)

Parameter	Maximum set down weight (lbf)	Surface weight reading (lbf)	Maximum pick up weight (lbf)	Surface weight reading (lbf)
0 BPM	-3,036	-2,689	17,485	38,292
0.3 BPM	-3,021	-3,405	17,529	38,286
1.1 BPM	-2,816	-2,518	18,037	37,995
Nitrified (0.9 BPM & 300 SCF/M)	-2,664	-2,039	18,330	37,710
Nitrified (0.9 BPM & 400 SCF/M)	-2,637	-4,115	18,330	37,566

APPENDIX IV – EMERGENCY PROCEDURE

EMERGENCY BOP OPERATIONS

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

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

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

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

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

Actuating the BOP System Hydraulic Controls

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

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

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

LEAK IN CT AT SURFACE

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

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

LEAK IN CT BELOW SURFACE

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

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

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

LEAK IN SURFACE PRESSURE CONTROL EQUIPMENT

Stuffing Box

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

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

Surface Leaks Other Than Stuffing Box

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

Note: Avoid collapse situation

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

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

Rotating Joint Leak

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

CT RUNS AWAY INTO WELL

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

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

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

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

CT IS PULLED OUT OF STUFFING BOX

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

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

CT COLLAPSED AT SURFACE

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

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

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

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

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

CT BREAKS AT SURFACE

If CT breaks at surface into two separate sections:

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

BUCKLED TUBING

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

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

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

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

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

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

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

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

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

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

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

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

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

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

CT STUCK IN HOLE PROCEDURES

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

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

Other factors to be considered are:

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

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

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

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

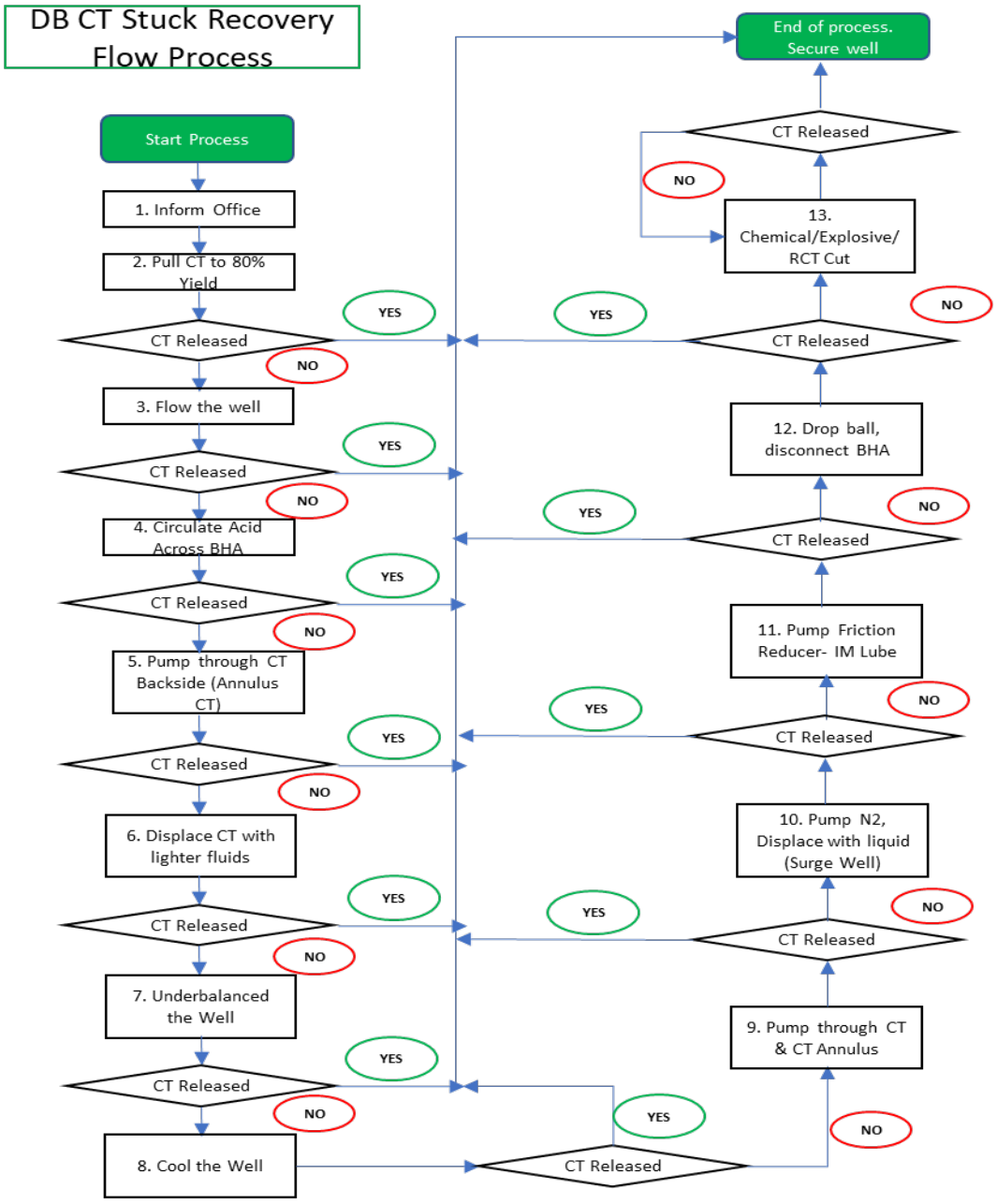
The following are options that may be appropriate depending on the particular circumstances:

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

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

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

STUCK CT COIL RECOVERY PROCESS

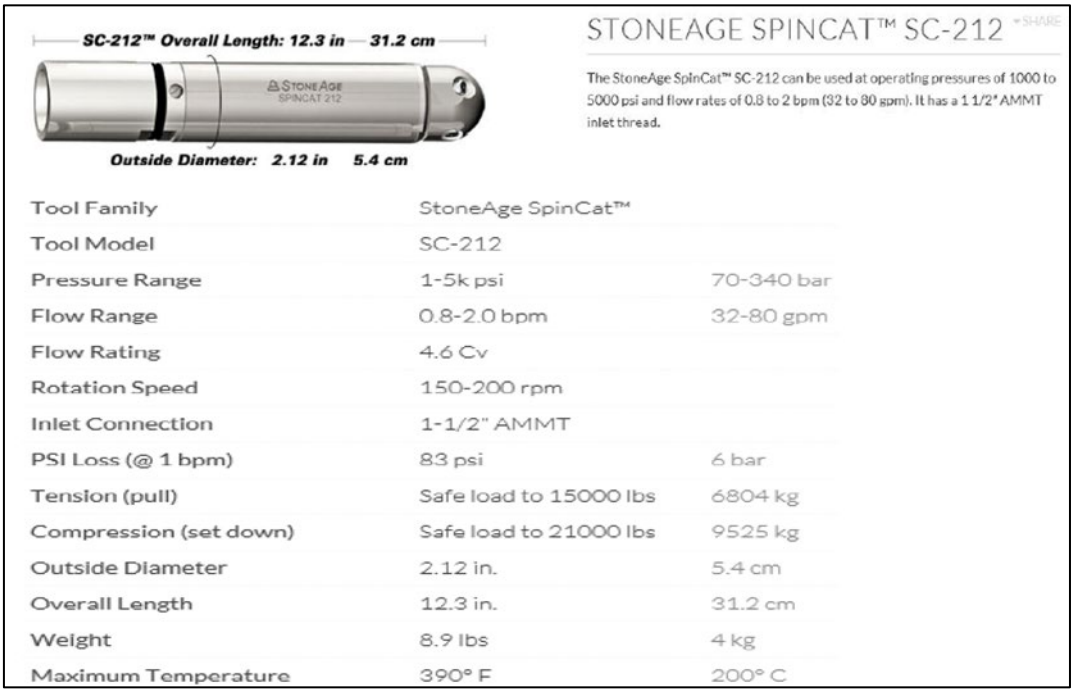


Precautionary Steps to avoid Stuck while Cleanout in Dual string Completion:

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

APPENDIX V – DOWNHOLE TOOL SPECS

2-1/8" SpinCat Nozzle



STONEAGE SPINCAT™ SC-212

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

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

2.187" FH OD FH CEMENT RETAINER

Weatherford

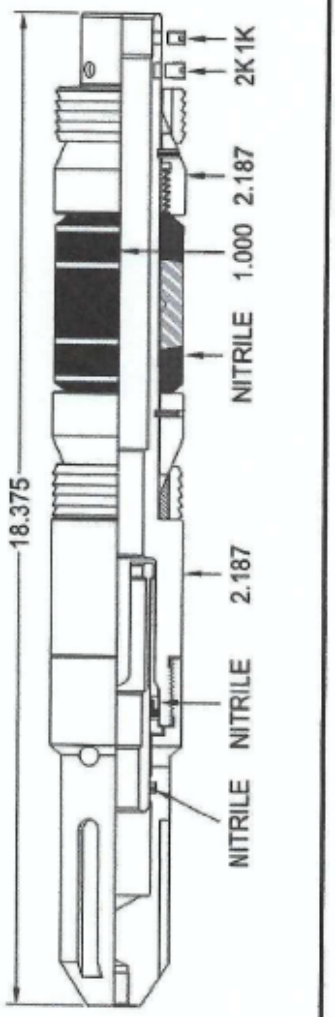
Thru-Tubing Intervention www.weatherford.com

PRODUCT DATA SHEET
As per API 11D1, Latest Specification

2.187" OD FH CEMENT RETAINER

Part Number	005-2187-500
Part Description	2.187 OD FH CEMENT RETAINER W/ Nitrile Element, Molded Seal & O-Ring (WL)
Part Type	CEMENT RETAINER
Part Characteristics	DRILLABLE
Service	REMEDIAL - TO P110 GRADE CSG
Metalic Materials	G2 DURABAR,1215,1010, DUCTILE IRON
Non Metalic Materials	NITRILE ELASTOMER
Casing Range	2-7/8" 6.4-6.5#
Casing ID	2.375 - 2.500
Drift Diameter	NA
Gauge OD	2.187
Seal Bore	1.000
Overall Length	18.375
Top Slip Length	1 .000
Temperature Range	325° F
Temperature Cycle Range for V3,V1 and V0	NA
Rate Performance Envelope for V4 to V0	NA
Pressure Rating for V6 and V5	5,000
Top Connection	2K STINGER / 10K DISCONNECT
Bottom Connection	.500-13 BOX
Setting Method	WL/TUBING/COIL TUBING
Setting Force	10,000 LBS
Quality Grade	Q3
Design Validation Grade	V6
Hydraulic Setting Tool	2.125 FH
Wireline Setting Tool	BAKER NO. 5
Setting Sleeve	005-2187-200
Adapter Rod	005-2187-206
Stinger, Locator	019-2187-070
Operational Manual Ref #	AOT-005-2187-500

Illustration



Document No. AOTPDS 005-2187-500, Revision 00, Date 3-26-2020, All dimensions are in inches

TUBING TALLY FOR WELL DULANG D-06S

CAMCO MALAYSIA SDN. BHD.

TUBING & COMPLETION EQUIPMENT SUMMARY

WELL D-06 FIELD DULANG COMPANY ENGINEER ZAILANI / YUSUF DATE 20 NOV 95

NOTE : Item No. 1 Is On Bottom

DISTANCE : Rotary Kelly Bushing to : SHORT STRING psi WP FLANGE ELEV: 14.93 m

TUBING : 2 7/8", 6.4 ppf, N-80, TKC4040, 2.441" ID

ITEM NO.	DESCRIPTION	LENGTH (meter)		DEPTH SET FROM RKB (m)	
	END OF TUBING			2153	971
1	WIRELINE RE-ENTRY GUIDE 2.441" ID	0	200	2153	771
2	2 7/8 CAMCO 'D' NO-GO NIPPLE 2.250" ID, 3.34" OD	0	360	2153	411
	P/N : 34179-000-00003 S/N : HJN 226 ✓	—	—	—	—
	BOTTOM OF PACKER - ELEMENT	1	830		
3	CAMCO HSD-3-SPS' DUAL HYD. PACKER S/N: BKP 112 ✓			2151	581
	ELEMENT - TOP OF PACKER	0	480	2151	101
	1 EA PUP JT	2	475	2148	626
4	2 7/8 CAMCO 'WP-1' SELECTIVE NIPPLE 2.312" ID / 3.76" OD	0	640	2147	986
	P/N : 33570-000-00002 S/N : HLN 541 ✓	—	—	—	—
5	1 EA - 20' BLAST JOINT - 2.441" ID	6	020	2141	966
6	1 EA - 10' BLAST JOINT -	3	006	2138	966
7	1 EA - 20' BLAST JOINT -	6	030	2132	936
8	2 7/8 CAMCO 'CSW-ID-T' SLIDING SLEEVE 2.312" ID, 3.76" OD	1	220	2131	716
	P/N : 22752-000-00002 S/N : HLO 111 ✓	—	—	—	—
	1 EA PUP JT	1	300	2130	416
	1 EA PUP JT	0	680	2129	736
9	2 7/8 CAMCO 'A-RO' TELESCOPIC SWIVEL JOINT ✓	1	065	2128	671
	1 EA PUP JT	1	905	2126	766
	BOTTOM OF PACKER - ELEMENT	1	890		
10	CAMCO HSD-3-SPS' DUAL HYD. PACKER S/N: BKP-197 ✓			2124	926
	ELEMENT - TOP OF PACKER	0	470	2124	456
	1 EA PUP JT	3	160	2121	296
	1 EA PUP JT	2	880	2118	416
11	2 7/8 CAMCO 'CSW-ID-T' SLIDING SLEEVE 2.312" ID	1	220	2117	196
	3.70" OD P/N: 22752-000-00002 S/N : HLO 124 ✓	—	—	—	—
	1 EA PUP JT	2	890	2114	306
	1 EA PUP JT	3	105	2111	201
	1 JOINT TUBING	9	562	2101	639
	1 EA PUP JT	3	750	2097	889
12	2 7/8 CAMCO 'KBMM' GASLIFT MANDREL LHT 812 2.441" ID ✓	2	060	2095	829
	1 EA PUP JT	3	740	2092	089
	12 JOINT TUBING	114	183	1977	966
	1 EA PUP JT	3	740	1974	166
13	2 7/8 CAMCO 'KBMM' GASLIFT MANDREL LHT 806 2.441" ID ✓	2	050	1972	116
	1 EA PUP JT	3	730	1968	386
	27 JOINT TUBING	256	166	1712	220
	1 EA PUP JT	3	750	1708	470
14	2 7/8 CAMCO 'KBMM' GASLIFT MANDREL 2.441" ID LHT 858 ✓	2	080	1706	390

APPENDIX VI – CIRCA SIMULATION

Cleanout from depth 1,840 m MDTHF to 2,112 m MDTHF (Cement Retainer)

SUMMARY OF FLOW RESULTS

Produced Fluids	
Pressure known at:	Reel Injection
Production Mode:	Not Perforated
Fluid Composition:	Not Perforated
Circulated Fluids	
Fluid Composition:	Water
Liquid:	1.10 bbl/min
Solids:	0.00 bbl/min
Circulation Point:	2112.00 m
HHP Required :	90.73 KW
COMPLETION:	
Wellhead Pressure.....	347.9 psi g
Hydrostatic pressure loss.....	1805.9 psi
Friction pressure loss.....	523.9 psi
Kinetic pressure loss.....	-9.8 psi
Equivalent Circulation Density[ECD]...	10.73 lb/gal (US)
Bottom Hole Pressure.....	2667.8 psi g
FROM CIRCULATION POINT TO WELLHEAD:	
Liquid transit time.....	19 min
Annular volume.....	24.9 bbl
Volume below circulation point.....	0.6 bbl
Total liquid volume.....	25.5 bbl
WORKSTRING:	
Liquid:	1584.0 bbl/day
Pressure at reel rotating joint.....	4500.0 psi g
Friction pressure loss on reel.....	1504.9 psi
Pressure inside WS at Gooseneck.....	2995.1 psi g
Hydrostatic pressure loss.....	-1749.3 psi
Friction pressure loss.....	1206.4 psi
Equivalent Circulation Density[ECD]...	2.57 lb/gal (US)

SUMMARY OF HOLE CLEANING RESULTS

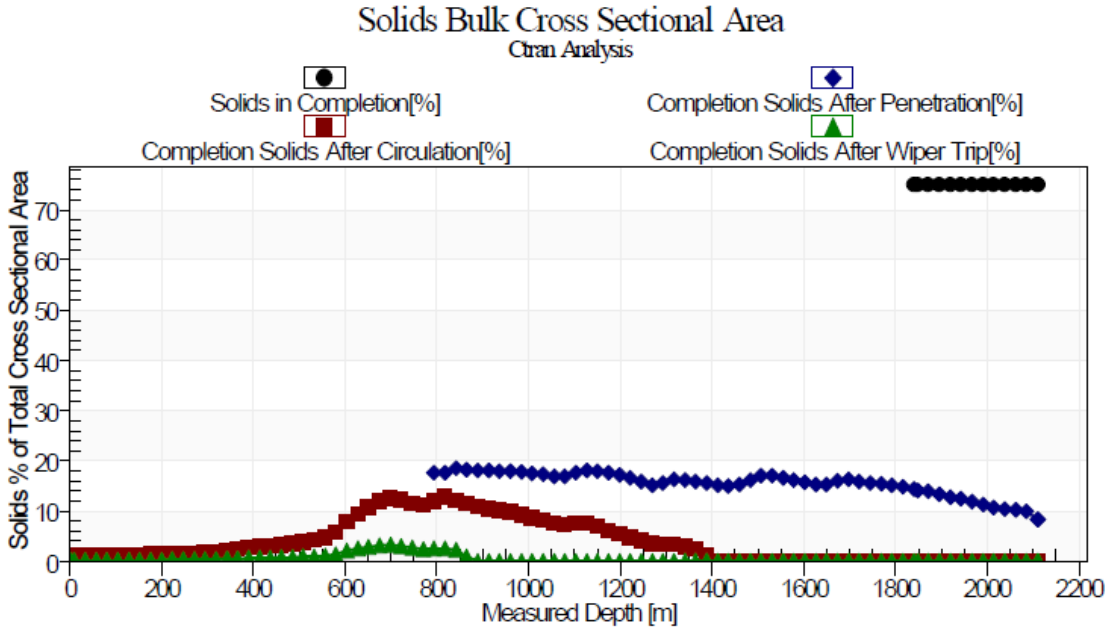
Initial Condition:	
% of fill interval occupied by solids before cleanout ...	75.0 %
Top of fill	1839.99 m
Deepest Circulation point	2111.99 m
Bottom of fill	2111.99 m
Initial Volume of Solids.....	3.9 bbl
Initial Mass of Solids.....	2715.6 lb
Solids type:	20/40 Bauxite Proppant
Fluid Description:	Water
Penetration Hole Cleaning Mode:	
Penetration rate.....	5.0 ft/min
Penetration time.....	2.97 hr
Solids volume in the well after penetration	3.9 bbl
Solids mass in the well after penetration	2715.6 lb
Circulation Hole Cleaning Mode:	
Hole circulation time	5.00 hr
Solids volume in the well after circulation.....	1.5 bbl
Solids mass in the well after circulation.....	1054.7 lb
Wiper Trip Hole Cleaning Mode:	
Wiper Trip Scheme:	User Specified rate, Tornado not
Wiper trip time	5.00 hr
Solids volume in the well after wiper trip	0.2 bbl
Solids mass in the well after wiper trip	140.4 lb
Volume of Fluids Pumped During Penetration, Circulation & Wiper Trip:	
Liquid Volume	856.2 bbl
Penetration, Circulation & Wiper Trip time	12.97 hr

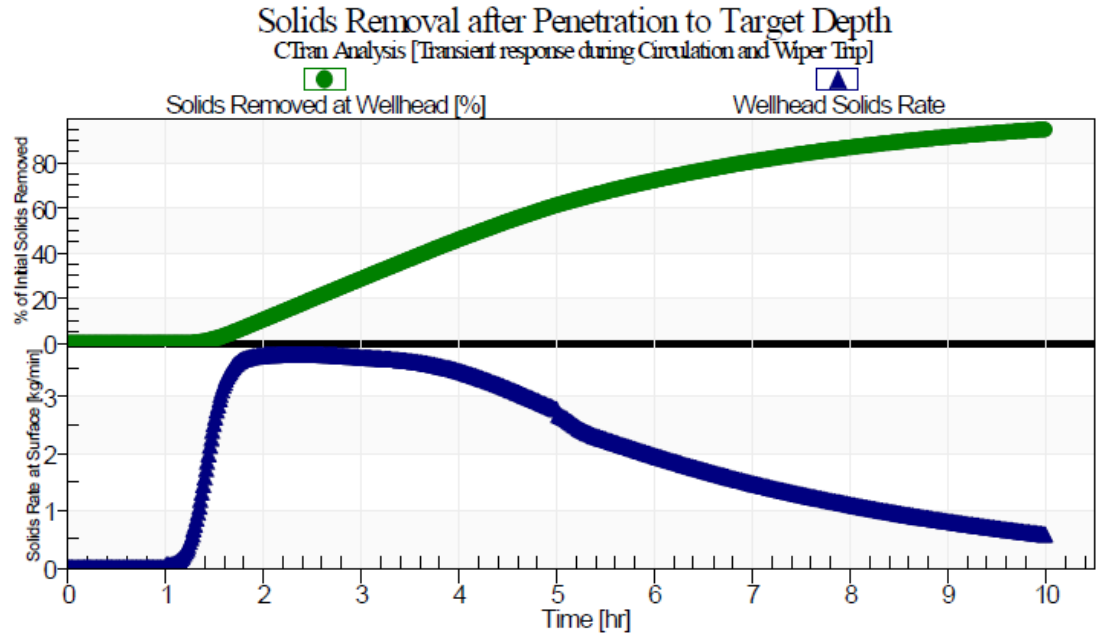
Flow State

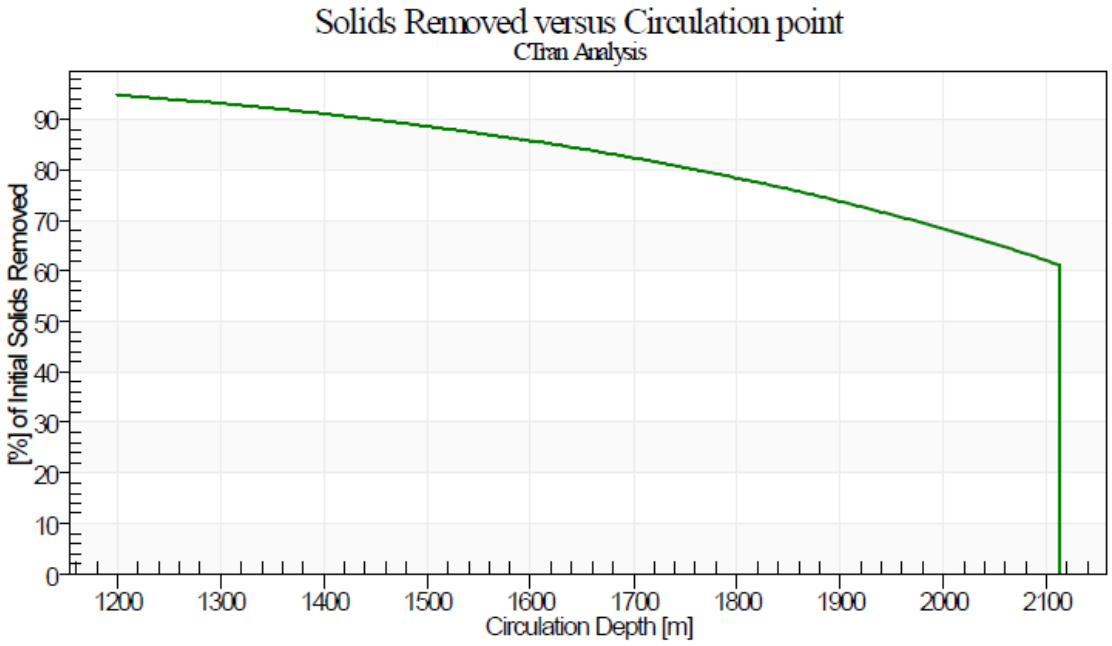
Measured Depth[Flow] *m*	Temperature	Completion Pressure	Workstring Pressure	Concentric Pressure	Completion Liquid Velocity *hr*	Workstring Liquid Velocity *m*	Concentric Liquid Velocity *ft/min*
0.0	60.0	347.9	2995.1	0.0	305	722	0
9.4	61.2	362.5	3002.7	0.0	305	722	0
33.1	64.3	399.7	3022.1	0.0	305	722	0
56.9	67.4	436.8	3041.5	0.0	305	722	0
80.7	70.4	473.8	3061.0	0.0	305	723	0
104.5	73.5	510.6	3080.3	0.0	305	723	0
128.2	76.5	547.3	3099.6	0.0	305	723	0
152.0	79.5	583.8	3118.8	0.0	306	723	0
175.8	82.6	620.3	3138.1	0.0	306	724	0
199.6	85.6	656.7	3157.4	0.0	306	724	0
223.3	88.6	693.0	3176.7	0.0	306	725	0
247.1	91.6	729.1	3195.8	0.0	306	725	0
270.9	94.6	764.8	3214.6	0.0	307	726	0
294.7	97.5	799.9	3232.8	0.0	307	726	0
318.4	100.4	834.3	3250.3	0.0	307	727	0
342.2	103.1	867.6	3266.9	0.0	307	727	0
366.0	105.8	900.1	3282.6	0.0	307	728	0
389.8	108.4	931.7	3297.5	0.0	308	728	0
413.5	110.9	962.4	3311.5	0.0	308	729	0
437.3	113.4	992.3	3324.7	0.0	308	730	0
461.1	115.8	1021.1	3336.9	0.0	308	730	0
484.9	118.0	1048.7	3347.8	0.0	309	731	0
508.6	120.2	1075.1	3357.6	0.0	309	731	0

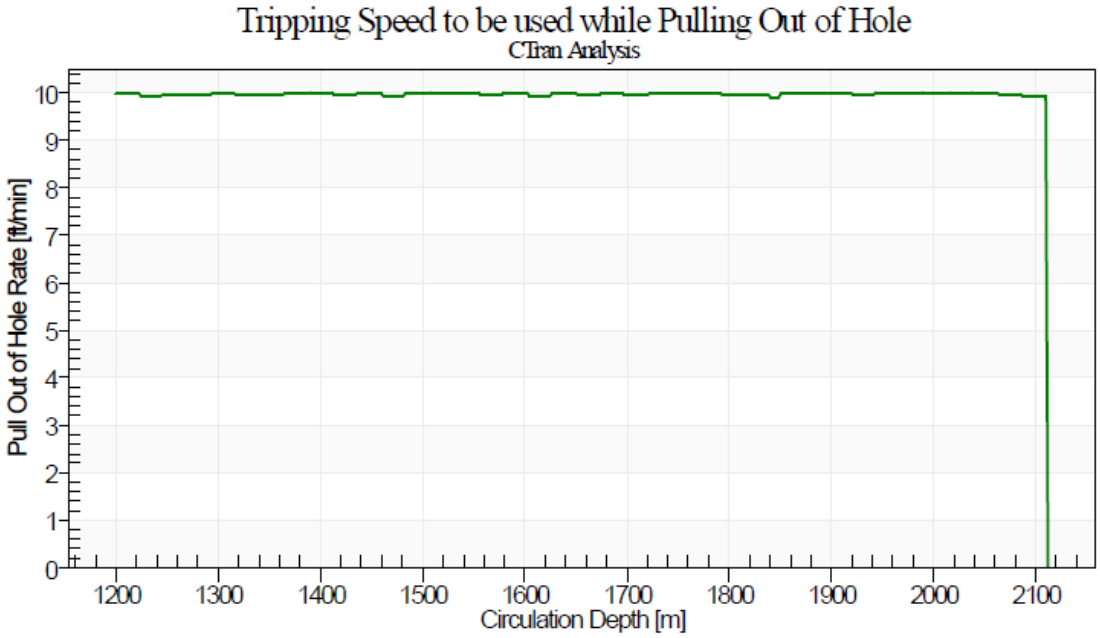
Flow State (continued)

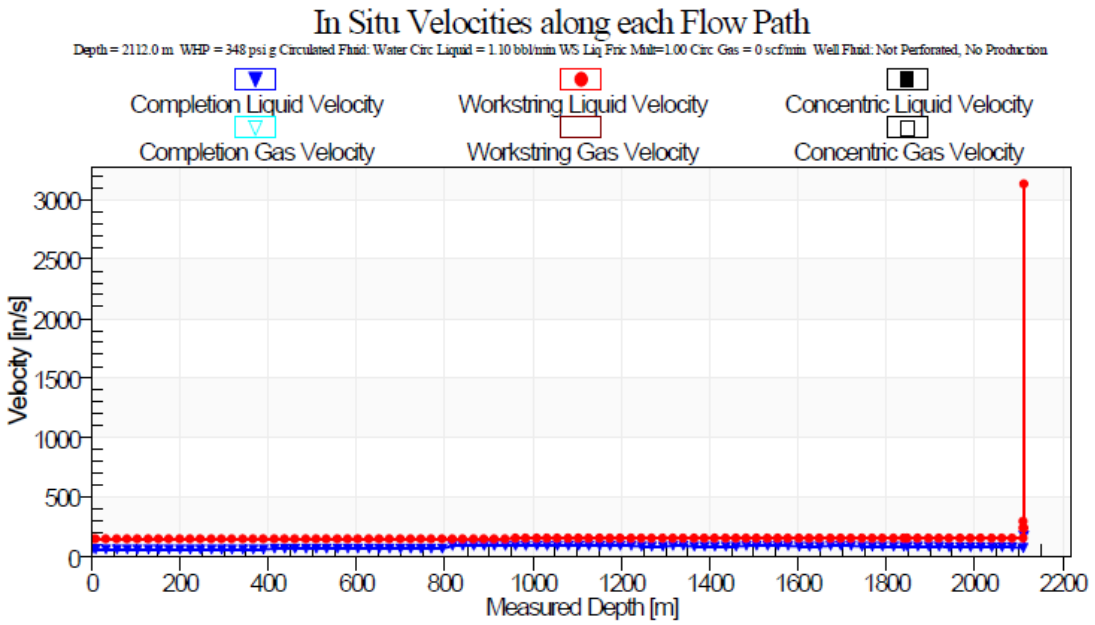
Measured Depth[Flow] *m*	Temperature	Completion Pressure	Workstring Pressure	Concentric Pressure	Completion Liquid Velocity *hr*	Workstring Liquid Velocity *m*	Concentric Liquid Velocity *ft/min*
2110.7	221.5	2636.8	3533.4	0.0	864	1460	0
2111.7	221.5	2640.9	3533.8	0.0	863	1183	0
2112.0	221.6	2642.1	3533.5	0.0	863	15643	0
2116.7	221.9	2645.9	0.0	0.0	0	0	0
2138.4	223.6	2664.1	0.0	0.0	0	0	0
2142.9	224.0	2667.8	0.0	0.0	0	0	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
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]
Time [hr]


Solids Removed versus Circulation point
CTran Analysis
[%] of Initial Solids Removed
0
10
20
30
40
50
60
70
80
90
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100
Circulation Depth [m]


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



Neu Dimension
Your Integrated Solutions Partner

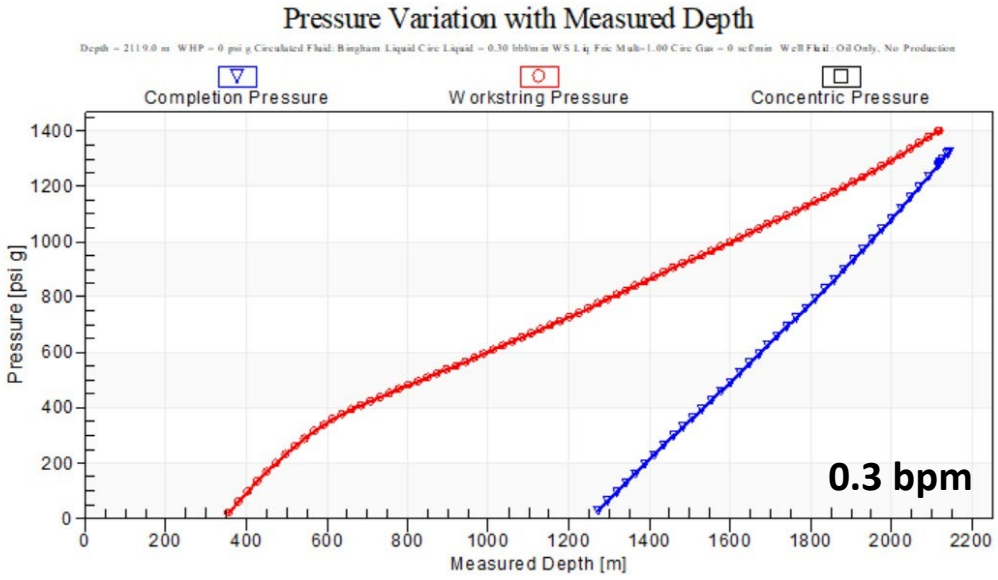
Sensitivity Analysis – Fill %

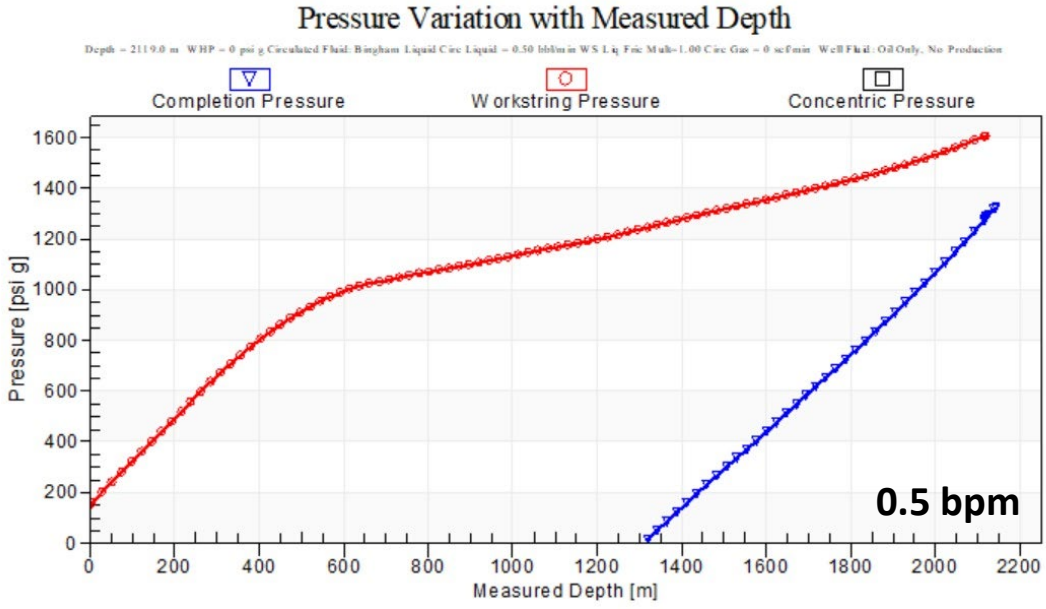
Constant parameter

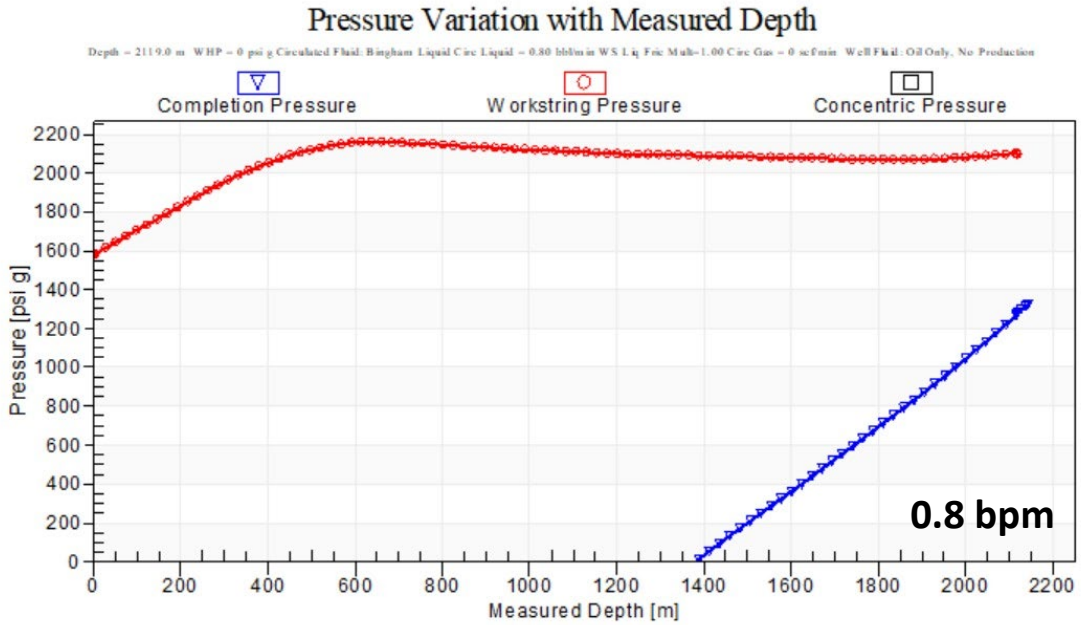
- 1.5" CT String
- Pump Rate = 1.1 bpm
- Solid Type (Heaviest density 20/40 Bauxite proppant with 16.69 ppg)
- Top of fill= 1,619 m MDTHF, Bottom of fill= 2,119 m MDTHF (Assume 10 bbls of cement left on top of CR due to underdisplace)
- Penetration Rate: 5 ft/min
- Circulation Time: 5 hrs
- Wiper Trip Rate: 10 ft/min

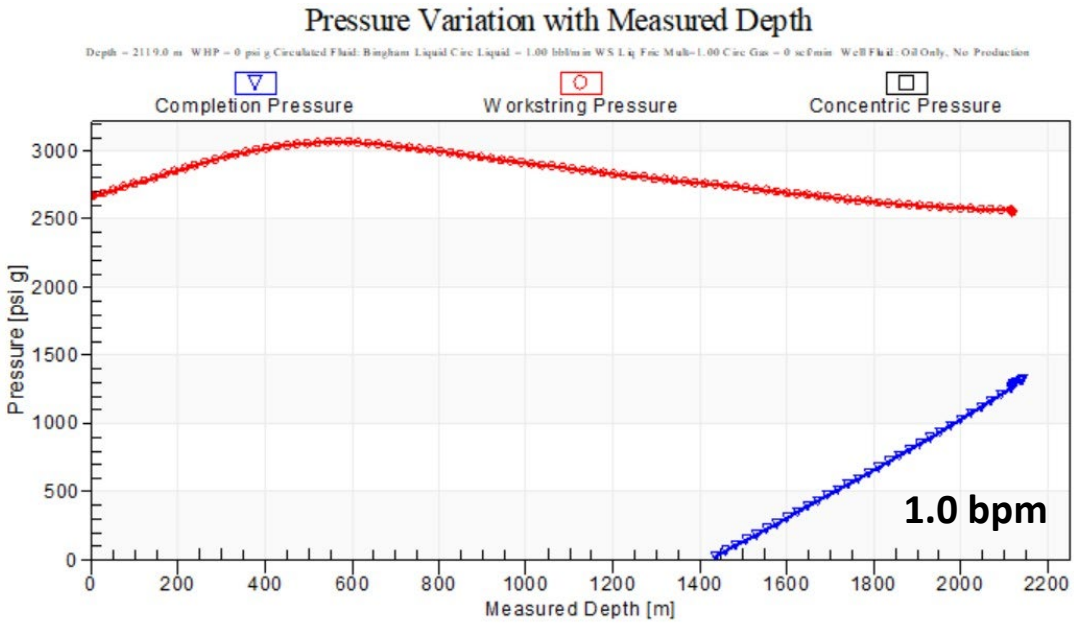
Fill %	Cleanout Time				Wiper Trip Depth (m)	Solid left in completion	Remarks
	Penetration Hour	Circulation Hour	Wiper trip Hour	**Total Hours**		%	
50%	5.47	5	5	**15.47**	**1,207**	**2.1**	Able to cleanout. Reduce wiper trip rate to improve cleanout efficiency.
75%	5.47	5	5	**15.47**	**1,207**	**2.8**	Able to cleanout. Reduce wiper trip rate to improve cleanout efficiency.
100%	5.47	5	5	**15.47**	**1,206**	**4.1**	Able to cleanout. Reduce wiper trip rate to improve cleanout efficiency. 30

APPENDIX VII – CERBERUS CEMENT PUMPING SIMULATION






Pressure Variation with Measured Depth
Completion Pressure
Workstring Pressure
Concentric Pressure
Pressure [psi g]
Measured Depth [m]
0.8 bpm


Pressure Variation with Measured Depth
Completion Pressure
Workstring Pressure
Concentric Pressure
Pressure [psi g]
Measured Depth [m]
1.0 bpm

APPENDIX VIII – CEMENT LAB REPORT

CLIENT/WELL INFORMATION

Client Name	PETRONAS CARIGALI SDN BHD			**District**	Kemaman
Well Name	DULANG D	**MD**	2,300 m	**Date Requested**	26/3/2024
Well Type	Horizontal	**TVD**	2,800 m	**Date Result Needed**	26/3/2024
Well Location	MALAYSIA	**GG**	1.71 °F/100ft	**Tubing Size**	3.5" Tubing
Job Type	Squeeze	**WD**	72m	**Casing Size**	8.5" OH
Job Description	CT CEMENTING - Blended Slag	**BHST**	228.00 °F	**Mud Type**	Oil-Based
UWI	0000000000000	**Surface Tempe**	91.00 °F	**Mud Density**	8.60 ppg
Rig #	NA	**BHCT**	°F	**Mud Density**	

SLURRY DESIGN

Slurry ID	387987-001	**Slurry Type**	Pilot	**Slurry Description**	SLURRY

SLURRY PROPERTIES

387987-001 | SLURRY

Slurry	15.00 ppg	**Liquid Volume**	61.05 %
Slurry Yield	1.37 ft³/sack	**Mix Fluid**	6.26 gal/sack
Mix Water	4.90 gal/sack	**Mix Fluid Total**	6.78 gal/sack

SLURRY COMPOSITION

387987-001 | SLURRY

Component Type	Component	Concentration	Lot/Batch	Source
Water	Sea Water	48.122 %	N/A	1. RIG
Additive	FP-32L	0.050 gal/sack	IM23386 - NG2	2. LAB
Additive	BA-58L	0.550 gal/sack	LOT 216	3. LAB
Additive	FL-70L	0.450 gal/sack	LA07CQ690M	4. LAB
Additive	ASA-304L	0.017 gal/sack	AS081G	5. LAB
Additive	CD-38L	0.180 gal/sack	IM23334	6. LAB
Additive	R-21LS	0.120 gal/sack	241123	7. LAB
Additive	EC-4	1.000 %BWOB	IM23388	8. LAB
Additive	S-8, Silica Flour	12.250 %BWOB	IM22229	9. LAB
Base	Blast Furnace Slag-Cementing	100.000 %	SL22004	9.1 LAB

387987-001 | SLURRY

Results:	Thickening Time	Analyst:	AZIZMOH
		Equipment:	N/A
Test Temperature		228.0 °F	
Test Pressure		2200 psi	
40 Bc		16:18 hh:mm	
70 Bc		16:29 hh:mm	
100 Bc		16:35 hh:mm	
Mix Time - Seconds		29 sec	
Final Pressure		2200 PSI	

387987-001 | SLURRY

Results:	Compressive Strength - Non Destructive	Analyst:	AZIZMOH
		Equipment:	N/A
24 hr		2453 PSI	
Final Strength		2467 psi	
50 psi		15:51 hh:mm	
500 psi		17:15 hh:mm	
Final Time		24:58:00 hh:mm	
Test Temperature		228.0 °F	
Test Pressure		2200 PSI	

387987-001 | SLURRY

Results:	Fluid Loss - Static Cell (Screw-in End Caps)	Analyst:	AZIZMOH
		Equipment:	N/A
Liquid Volume		26.0 cc	
Test Time		30:00:00 mm:ss	
Test Temperature		228.0 °F	
API Fluids Loss Calculated		52.0 cc	

387987-001 | SLURRY

Results:	Free Fluid	Analyst:	AZIZMOH
		Equipment:	N/A
Test Temperature		190.0 °F	
Deviation Angle		45°	
Sample Volume		250 cc	
Liquid Volume		0.0 cc	
% Free Fluid		0.0 %	
Channeling		NO	
Settling		NO	

387987-001 | SLURRY

Results:	Static Gel Strength	Analyst:	AZIZMOH
		Equipment:	N/A
Test Temperature		228 °F	
Test Pressure		2200 psi	
Time to reach 100 lb/100ft²		15:09 hh:mm	
Time from 100 to 500 lb/100ft²		0:11 hh:mm	
Time to reach 500 lb/100ft²		15:20 hh:mm	

387987-001 | SLURRY

Results:	Rheology - Temp 1	Analyst:	AZIZMOH
		Equipment:	
Test Temperature		80.0 °F	
API PV		147 cP	
API YP		11 lbf/100ft²	
10 sec Gel Strength		5.0 FDR	
10 min Gel Strength		9.0 FDR	

RPM	300	200	100	60	30	6	3
Up	153.0	111.0	67.0	48.0	26.0	9.0	6.0
Dwn		109.0	65.0	46.0	23.0	8.0	5.0
Avg		110.0	66.0	47.0	24.5	8.5	5.5

387987-001 | SLURRY

Results:	Rheology - Temp 2	Analyst:	AZIZMOH
		Equipment:	
Test Temperature		190.0 °F	
API PV		95 cP	
API YP		8 lbf/100ft²	
10 sec Gel Strength		5.0 FDR	
10 min Gel Strength		13.0 FDR	

RPM	300	200	100	60	30	6	3
Up	99.0	74.0	42.0	32.0	19.0	7.0	5.0
Dwn		73.0	42.0	30.0	17.0	6.0	4.0
Avg		73.5	42.0	31.0	18.0	6.5	4.5

LAB NOTES

1. Water Temperature : 81 degF. Cement Blend Temperature : 81 degF
2. Mixing time 22 seconds @ <35 sec in 600ml blender
3. Yield calculation is based on 1 cuft of neat slag : 87 lbs/sacks
4. Mixing Sequence: 1) FP-32L, 2) ASA-304L, 3) BA-58L, 4) FL-70L, 5) CD-38L, 6) R-21LS, 7) EC-4, 8) Blend Slag

EXPANSION TEST

DULANG D

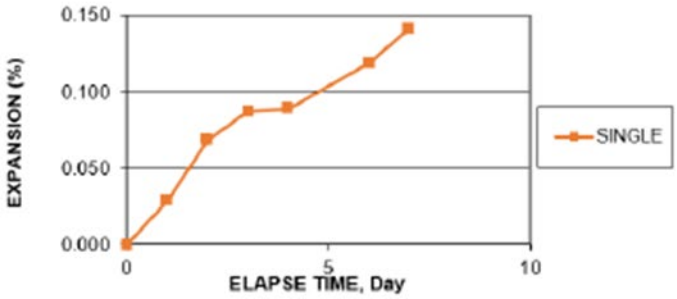
DESIGN : SLAGMENT + 12.25% S-8(BWOC) + 1% EC-4 (BWOC) + 0.05GPS FP-32L + 0.017 GPS ASA-304L + 0.55GPS BA-58L + 0.45GPS FL-70L + 0.18GPS CD-38L + 0.12GPS R-21LS @ 15.0PPG

Curing Temperature: 228 degF

Curing Pressure: 3000psi

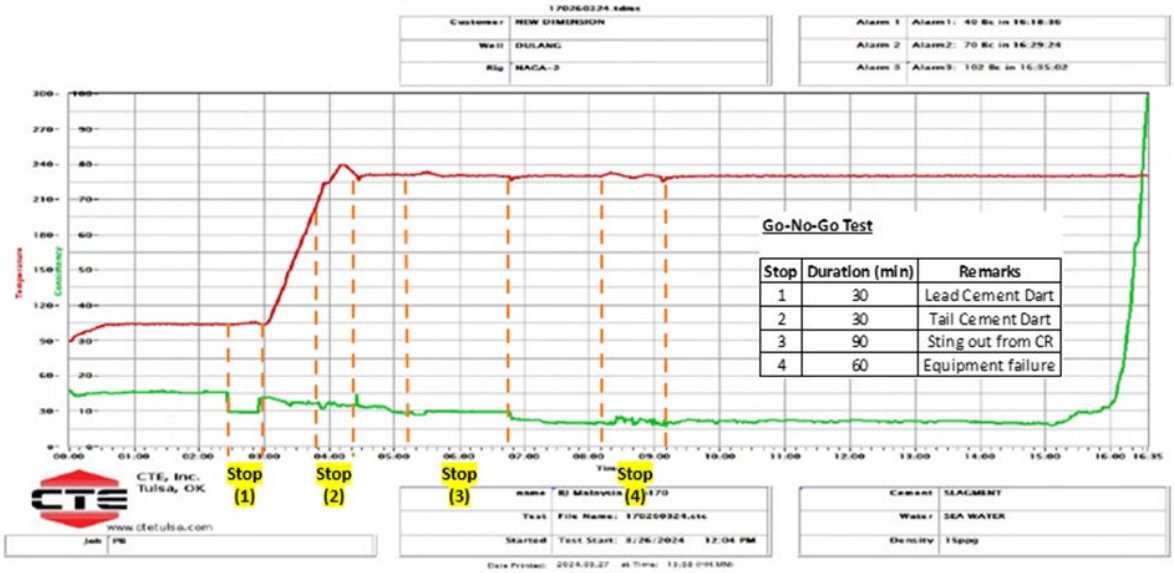
SINGLE SLURRY

Day	Date	Reading (in)	Expansion (%)
0	31/3/2024	0.4476	0.000
1	1/4/2024	0.45070	0.028
2	2/4/2024	0.4516	0.068
3	3/4/2024	0.45365	0.087
4	4/4/2024	0.4538	0.088
6	6/4/2024	0.4571	0.118
7	7/4/2024	0.45965	0.141



387987-001 | SLURRY

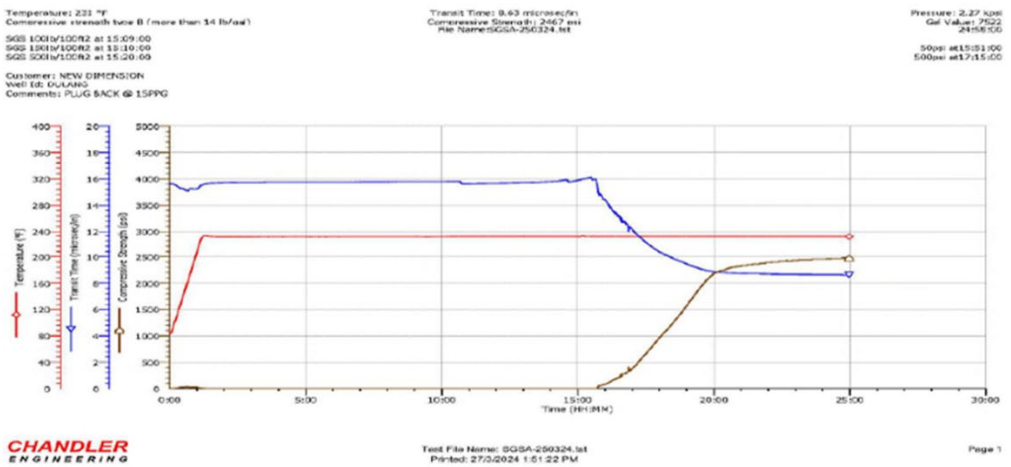
Profile:	Thickening Time	Description:	



Stop	Duration (min)	Remarks
1	30	Lead Cement Dart
2	30	Tail Cement Dart
3	90	Sting out from CR
4	60	Equipment failure

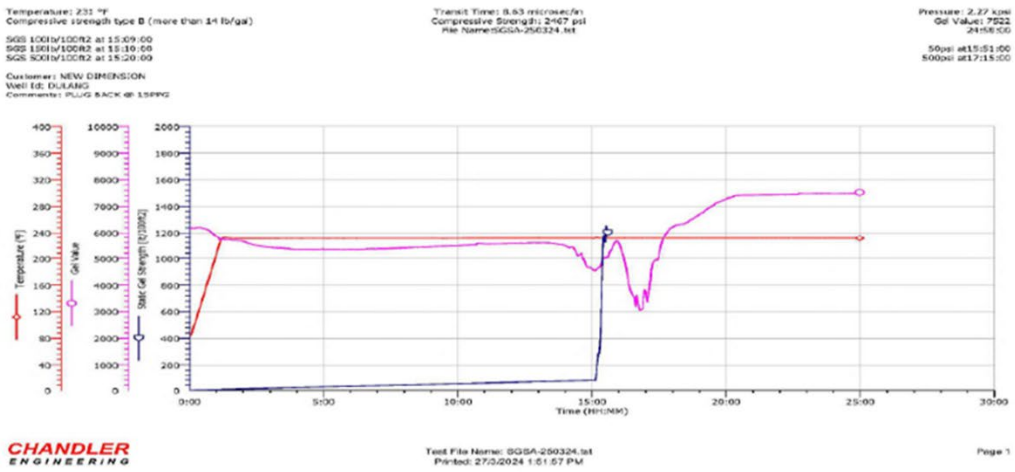
387987-001 | SLURRY

Profile:	Compressive Strength - Non Destructive	Description:	



387987-001 | SLURRY

Profile:	Static Gel Strength	Description:	



SUMMARY

Slurry Design

SLURRY: 48.122% Sea Water + 0.05 gal/sack FP-32L + 0.55 gal/sack BA-58L + 0.45 gal/sack FL-70L + 0.017 gal/sack ASA-304L + 0.18 gal/sack CD-38L + 0.12 gal/sack R-21LS + 1%BWOB EC-4 + 12.25%BWOB S-8, Silica Flour + 100% Blast Furnace Slag-Cementing Process (BASE ONLY)

Type	Component	Concentration	Lot/Batch	Mixing Order/Source
Water	Sea Water	48.122 %	N/A	1. RIG
Additive	FP-32L	0.05 gal/sack	IM23386 - NG2	2. LAB
Additive	BA-58L	0.55 gal/sack	LOT 216	3. LAB
Additive	FL-70L	0.45 gal/sack	LA07CQ690M	4. LAB
Additive	ASA-304L	0.017 gal/sack	AS081G	5. LAB
Additive	CD-38L	0.18 gal/sack	IM23334	6. LAB
Additive	R-21LS	0.12 gal/sack	241123	7. LAB
Additive	EC-4	1 %BWOB	IM23388	8. LAB
Additive	S-8, Silica Flour	12.25 %BWOB	IM22229	9. LAB
Base	Blast Furnace Slag-Cementing Process (BASE ONLY)	100 %	SL22004	9.1 LAB

Slurry Properties		Fluid Loss Test		Free Fluid Test		SGS	
Density:	15 ppg	Test Temp:	228 °F	Test Temp:	190 °F	Time to 100lb/100ft²:	15:09 hh:mm
Yield:	1.372 ft³/sack	Liq Vol(30min):	26 cc	Free Fluid (2hr):	0 cc		
Mix Water:	4.898 gal/sack			% Free Fluid:	0 %		
Mix Fluid:	6.264 gal/sack	Cal API Fluid Loss (30min):	52 cc	Deviation Angle:	45°	Time to 500lb/100ft²:	15:20 hh:mm
						Time to 100-500lb/100ft²:	0:11 hh:mm

Rheology:		300 rpm	200 rpm	100 rpm	60 rpm	30 rpm	6 rpm	3 rpm	PV	YP	Gel Strength	
											10 sec	10 min
@80.0 °F		153.0	110.0	66.0	47.0	24.5	8.5	5.5	147	11	5.0	9.0
@190.0 °F		99.0	73.5	42.0	31.0	18.0	6.5	4.5	95	8	5.0	13.0

Thickening Time:				40 bc		70 bc	100 bc	Mix Time	
@228 °F				16:18 hh:mm		16:29 hh:mm	16:35 hh:mm	29 sec	

Compressive Strength:

Temp.	15:51 hh:mm	17:15 hh:mm					24 hours			
@228 °F	50 psi	500 psi					2453 PSI			

Lab Notes

Mixing Sequence: 1) FP-32L, 2) ASA-304L, 3) BA-58L, 4) FL-70L, 5) CD-38L, 6) R-21LS

DISCUSSION

APPENDIX

ACRONYMS AND DEFINITIONS

GG	Geothermal Gradient
WD	Water Depth
TVD	True Vertical Depth
MD	Measured Depth
BHST	Bottom Hole Static Temperature

APPENDIX IX – DECISION TREE

DECISION TREE