DIMENSION BID

PETRONAS

DULANG D03
ACIDIZING

Revision:	0
Prepared for:	Zhafran Rahman
Date Prepared:	15th May 2023
Well:	D-03
Field:	DULANG
Operation Region:	PMA
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DESIGN VERIFICATION

PREPARED BY DB CTS Operation Engineer	Muhammad Hafiz	17/05/2023 Date
REVIEWED BY DB CTS Technical Advisor	Kung Yee Han	17/05/2023 Date
APPROVED BY DB CTS Operation Manager	Aliff Adenan	17/05/2023 Date
APPROVED BY PCSB Dulang Well Intervention Engineer	Zhafran Rahman	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	Asraf M Nazri	Date

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

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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
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4	Mohammad Faizal Ali	Operation Engineer	DB	Kemaman	013 – 736 1046

REVISION HISTORY

Rev. No	Section	Date	Revised By
0	All	13/05/2023	Muhammad Hafiz

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

To perform acidizing to remove flow restriction. Suspected sand/scale built up on zone E10/11, E12/13 and E-14

BACKGROUND

Dulang D003S01-TS is a single water injector (Type 1) with 3-1/2" completion, completed on 3rd October 1995. Currently the well is injecting and experienced decline in injection rate / injectivity . Tubing restriction (suspected scales, sand accumulation in tubing / wellbore casing) with historical CT-Sand Scale Clean Out in 2015.

2.75" Gauge Ring was run and manage to tag D-No-Go Nipple @2,324m MDTHF on March 2017

WELL DATA

Input Parameter	Parameter Value
Field	Dulang Delta well D-03
Max. Deviation (degrees)	67.7 degree
Min. Restriction (inch)	2.75" (NO-GO Nipple) @ 2,319.9m MDTHF
Tubing Specification	3-1/2" Production Tubing, 9.2# ppf, N-80
Type of Fluid & Density	9.3 PPG NaCl (based on Completion Fluid data in Well Diagram)
Top of Fluid	TBA
Current Well Status	Injecting
Depth of zone (*Based on well Schematic*)	**Primary** E12 (2,363.8 – 2,370m MDTHF) E13 (2,372.5 – 2,390.7m MDTHF) E14 (2,405 – 2,416m MDTHF) **Secondary** E10 (2,335- 2,340m MDTHF) E11 (2,343 – 2,351m MDTHF)
Reservoir Pressure (*Based on MPLT 2017*)	1,430psi
Reservoir Temperature	205 degF
Porosity	TBA
Permeability	TBA
Fracture Gradient	0.6 - 0.70psi/ft
Additional Information / Notes / Special Requirement:	
• One leak point at 184.9m MDTHF – MPLT Run March 2017	

OPERATION SUMMARY

Item	Job Description	Remark
A	Slickline	1. RIH FOR TCC UNTIL PBTD
B	Pumping Operation	1. BULLHEADING INJECTIVITY PRE-CTU OPERATION
C	Slickline	1. SGS TO DETECT FLUID LEVEL
D	CT Operation	1. RUN #1: WELL, UNLOADING WITH 2.125" UPWARD JETTING NOZZLE 2. RUN #2: 2.125" DOWNWARD JETTING NOZZLE ACIDIZING ON ZONE E10/11, E12/13 & 14
D	Pumping Operation	1. BULLHEADING INJECTIVITY POST-CTU OPERATION

WELL DIAGRAM

WELL D-03 : SINGLE WATER INJECTOR (TYPE 1)

DATE OF COMPLETION : 03 OCTOBER, 1996
RIG : TEKNIK BERKAT
TUBING : 3-1/2" 9.2 PPF, N-80 , TKC-4040
X-MAS TREE : INGRAM CACTUS, SINGLE 3-1/8" X 11", 3000 PSI
PACKER FLUID : 9.3 PPG 3% KCl + NaCl + 0.05% NALCO 3900 BIOCIDE & CORR. INHIBITOR

CASING :
26"DRIVE PIPE A-36 CONN.202 PPF@185.5m-MDDF
18-5/8" X-56 cOND 87.5 ppf @ 640.0m-MDDF
13 3/8" K-55 SURF. 54.6 PPF, BUTT @ 1713 m MDDF
9 5/8" N-80 PROD.40 PPF @ 2502.0 m MDDF
PBTD : 2471.0 m MDDF
MAXIMUM DEVIATION : 14.93m
RTE TO TUBING HANGER : 67.7 DEG

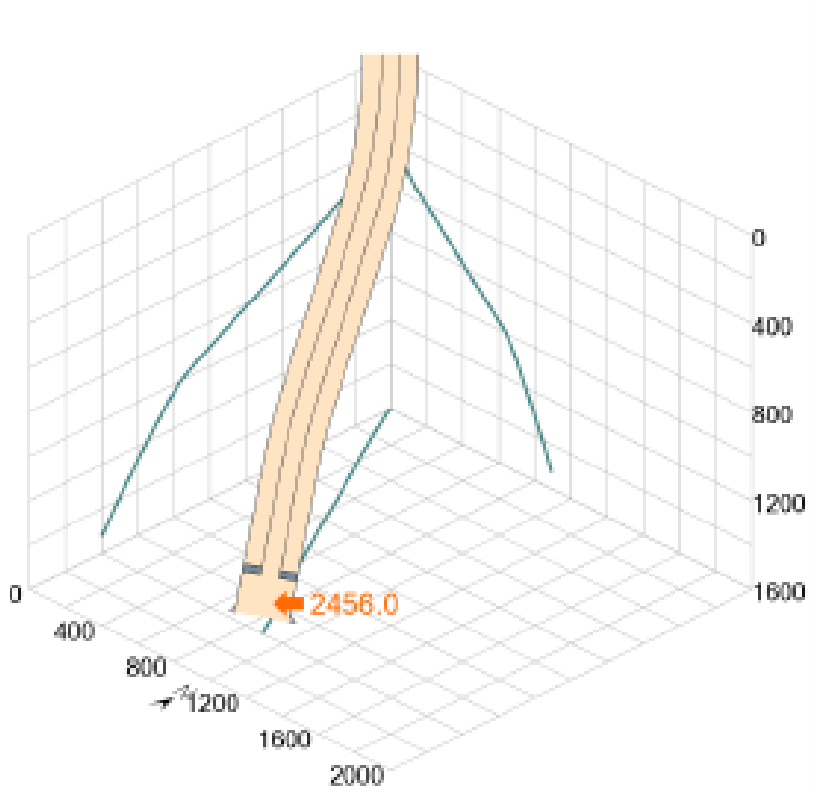
DEPTH mMDTHF	TUBING STRING	DEPTH mMDTHF	COMPLETION	MIN ID (in)	STATUS
			1/4" CONTROL LINE		
RIH with size 2.0" LIB tagged HUD @239m-MDTHF (1/9/2015)		145.7	FLOW COUPLING	2.867	
		146.5	TRDP-4A-LS- SCSSV	2.812	
		149.8	FLOW COUPLING	2.867	
		299.8	WP-1 NIPPLE	2.812	
		635.3	KBMM-M SPM	2.992	DV
		2308.1	'CSW-1-DT' SSD	2.812	
		2312.1	CENTRALIZER	2.992	
		2313.7	LOC. SEAL ASSY	2.867	
		2315.0	BAKER PERM. PACKER	2.992"	
		2315.3	SEAL BORE EXT	2.992	
		2319.0	END OF SEAL BORE EXT	2.992	
		2319.9	D' NO-GO NIPPLE W/2.69 ID	2.75"	
		2320.9	WEG		
		2321.1	END OF TUBING	2.992	
SAND E-10/11 2335 - 2340 2342 -2350.7 2343 -2351 E-12/13 2363.8 - 2370 2372.5 - 2390.7 2405 - 2416					

PBTD @ 2456.0m-MDTHF
TD @ 2495m-MDTHF

MPLT : 7/2/2007 / TBCLR : 24/8/2015 / SCO : 9/12/2015

02/Sept/2013

WELL 3D PLOT



Well name:	Dulang D03
Total depth:	2510.1 m
Max Inclination:	67.7° at 1283.7 m
Max DLS:	5.173 °/100ft at 1777.8 m
Min ID:	2.750 in at 2319.9 m
WHP:	150 psi

TREATMENT VOLUME

Description	Details
Tubing Specification	3-1/2” 9,2ppf# N-80, TKC-4040
Production Casing Specification	9-5/8” x 40# N-08 PROD.

Completion Volume

Tubing																
Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
THF to EOT	3 1/2	2.992	9.2							0.00870	0.00	2321.10	0	7616	**7616**	**66.2**
															TOTAL	**66.2**

A-Annulus (PCP)																
Type	External Pipe			Internal Pipe			Internal Pipe			Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	Barrel/lin (ft)	m	m	ft	ft	ft	
THF to Packer#1	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	0.00	2315.00	0	7596	**7596**	**486**

Near Wellbore Area																
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 EOT	9 5/8	8.835	40	3 1/2	2.992	9.2				0.06393	2315.00	2321.10	7596	7616	**20**	**1.3**
EOT to E-10/11 Top Perf	9 5/8	8.835	40							0.07582	2321.10	2335.00	7616	7661	**46**	**3.5**
E-10/11 Top Perf to E-12/13 Bottom Perf	9 5/8	8.835	40							0.07582	2335.00	2416.00	7661	7927	**266**	**20.2**
E-12/13 Bottom Perf to PBTD	9 5/8	8.835	40							0.07582	2416.00	2456.00	7927	8058	**131**	**10.0**
															TOTAL	**34.8**

Penetration Volume

Penetration Volume to E-10/11 Option 1														
Type	Radial Treatment Diameter			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E-10/11		21.625		9 5/8			6	0.36428	2335.00	2340.00	7661	7678	**16**	**6**
E-10/12		21.625		9 5/8			6	0.36428	2342.00	2350.70	7684	7713	**29**	**10**
E-10/13		21.625		9 5/8			6	0.36428	2343.00	2351.00	7687	7714	**26**	**10**
													Porosity	**0.27**
													Total	**7.0**

Penetration Volume to E-12/13 Option 1														
Type	Radial Treatment Diameter			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E-12/13		57.625		9 5/8			24	3.13568	2363.80	2370.00	7756	7776	**20**	**64**
E-12/13		57.625		9 5/8			24	3.13568	2372.50	2390.70	7784	7844	**60**	**187**
E-12/13		57.625		9 5/8			24	3.13568	2405.00	2416.00	7891	7927	**36**	**113**
													Porosity	**0.28**
													Total	**102.0**

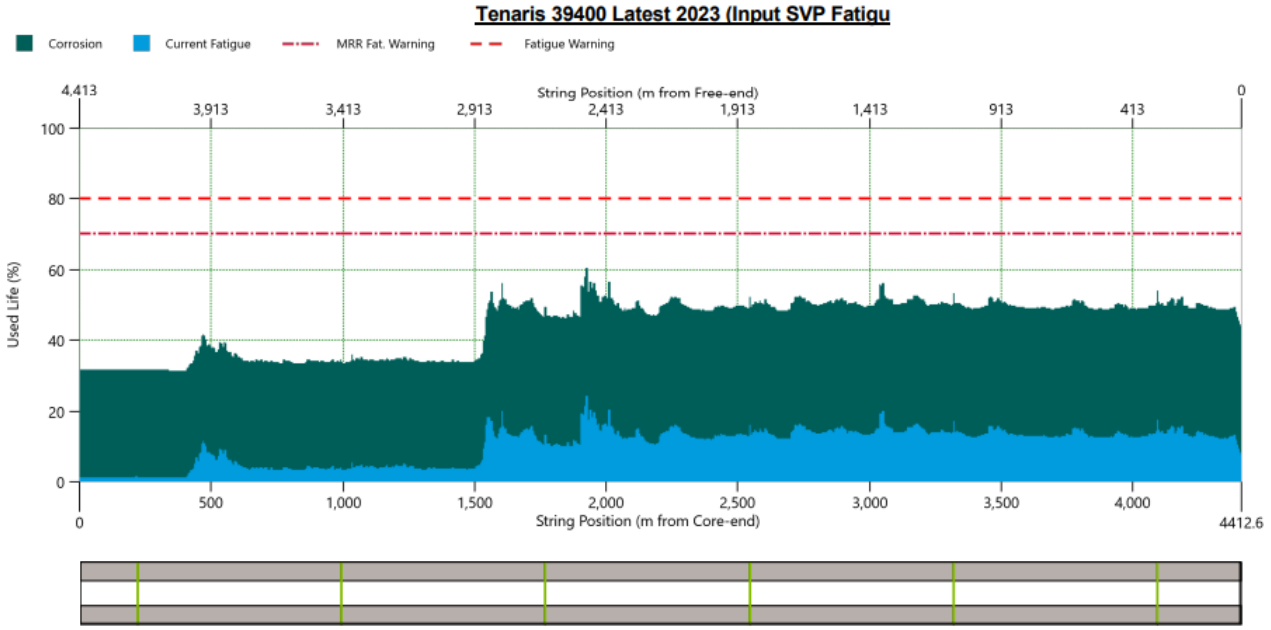
5ft Penetration														
Type	Radial Treatment Diameter			Internal Pipe			Penetration	Caps	From	To	From	To	Length	Total Volume (bbls)
	OD (inch)	ID (inch)	W(lb/ft)	OD (inch)	ID (inch)	W(lb/ft)	(in)	Barrel/lin (ft)	m	m	ft	ft	ft	
E-10/11		129.625		9 5/8			60	16.23209	2335.00	2340.00	7661	7678	**16**	**266**
E-10/11		129.625		9 5/8			60	16.23209	2342.00	2350.70	7684	7713	**29**	**463**
E-10/11		129.625		9 5/8			60	16.23209	2343.00	2351.00	7687	7714	**26**	**426**
E12/13		129.625		9 5/8			60	16.23209	2363.80	2370.00	7756	7776	**20**	**330**
E12/13		129.625		9 5/8			60	16.23209	2372.50	2390.70	7784	7844	**60**	**969**
E12/13		129.625		9 5/8			60	16.23209	2405.00	2416.00	7891	7927	**36**	**586**
													Porosity	**0.28**
													Total	**271.4**

CT STRING INFORMATION

OD (in)	Spec	W/T (in)	ID (in)	Length (ft)
1.5	HS-90	0.125	1.25	14,535
CT Volume: 23 bbls				

CT STRING FATIGUE

- Current **used life** for Tenaris #39400 is at **60.46%**



DIMENSION BID
WELL INTERVENTION | PERFORATION SERVICES

CT Pipe Management Tracking Sheet

CT String Details

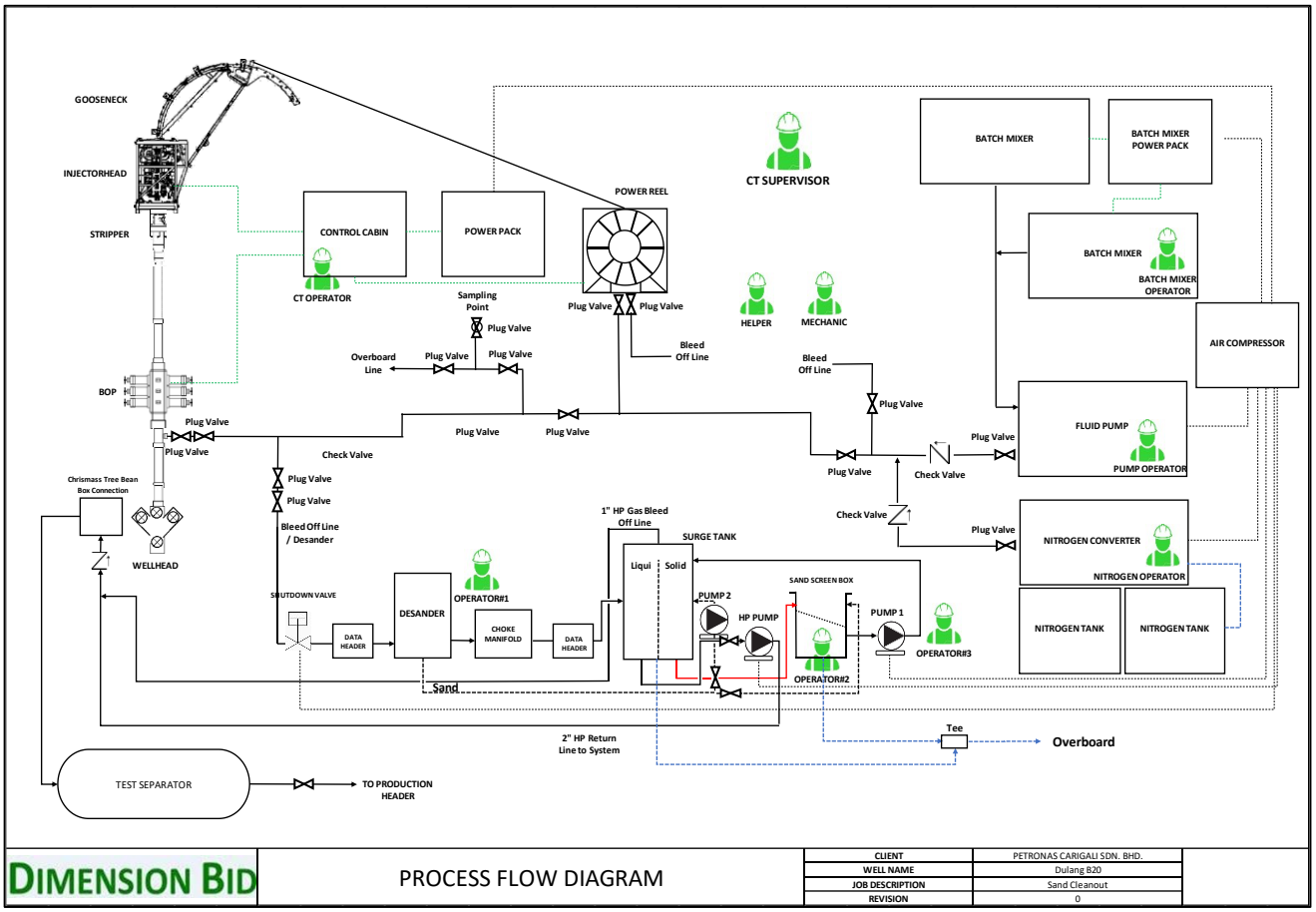
String	HS 39400
Manufacturer	TENARIS 39400
OD	1.5"
Grade	90 GRADE
Initial Spooled Length, ft	15,751
Cable (length/ID Num)	15800/1.5
Weld Type	
Tubing Weight	
Commision Date	1-Oct-20

Wall Thicknes
NO RECORD

Cum. Fatigue = Last Cum. Fatigue + Job Fatigue
Cum. Corrosion = Last Cum. Corrosion + Job Corrosion
Used String Life = Max Fatigue + Cum Corrosion

Run #	Date	Client Name	Field Name	Well Num	Job type	Running ft ft	Cum. Run ft	Max CTW lb	Job Description	Job Fatigue %	Job Corrosion %	Max Fatigue %	Cum. Corrosion %	Used String Life %
46	21-Apr-23	PCSB	DLB	B16	TRIM COILED 20FT	NA	NA	NA	TRIM COILED AFTER 3 RUN	0	0	0	28.37	0
47	22-Apr-23	PCSB	DLB	B16	RUN#5 TO CLOSE SSD.	9383	282,194	21500	TO CLOSE SSD#2	8.29	2	21.78	30.37	52.15
48	25-Apr-23	PCSB	DLB	B16	RUN#6 PXN PRONG RETRIEVAL USING JDC.	9383	291,577	22,000	RETRIEVE PRONG FROM PLUG	1.06	1	21.14	31.37	52.51
49	26-Apr-23	PCSB	DLB	B16	RUN#7 SCD UNTIL TOP OF PLUG	9383	300,960	13,600	CLEAN OUT OF TUBING UNTIL PXN PLUG	2.42	2	23.49	33.37	56.86
50	27-Apr-23	PCSB	DLB	B16	TRIM COILED 1IFT	NA	NA	NA	TRIM A COILED AFTER 3 RUN	0	0	0	33.37	0
51	28-Apr-23	PCSB	DLB	B16	RUN#8 PERFORM PXN PLUG RETRIEVAL	9383	300,960	29,300	RETRIEVE PXN PLUG	1.06	1	22.78	34.37	57.15
52	29-Apr-23	PCSB	DLB	B16	RUN#9 PERFORM PXN PLUG RETRIEVAL	9383	310,343	24,300	RETRIEVE PXN PLUG	2.11	1	22.57	35.37	57.94
53	1-May-23	PCSB	DLB	B16	RUN#10 RUN GRCCL TOOL	9383	319,726	12,500	RUN GRCCL TOOL	1.06	1	22.36	36.37	58.73
54	2-May-23	PCSB	DLB	B16	RUN#11 RUN SMART BLASTER TO TUBING CUT	9383	329,109	15,700	PERFORM TUBING CUT	0.66	1	22.3	37.37	59.67
55	2-May-23	PCSB	DLB	B16	TRIM COILED 10FT	0	0	0	TRIM A COILED AFTER 3 RUN	0	0	0	37.37	37.37
56	4-May-23	PCSB	DLB	B16	RUN#12 TO CLOSE SSD#1	9383	338,492	14,700	TO CLOSE SSD#1	2.91	1	21.59	38.37	59.96
57	5-May-23	PCSB	DLB	B16	TRIM COILED 10FT	0	0	0	TRIM A COILED TO MAKE A NEW CONNECTOR	0	0	0	38.37	0
58	5-May-23	PCSB	DLB	B31	RUN#1 DEPTH CORRELATION	712	339,204	3,100	DEPTH CORRELATION	0.57	0.5	21.09	38.87	59.96
59	6-May-23	PCSB	DLB	B32	RUN#2 ACID TREATMENT	712	339,916	5,500	ACID TREATMENT	0.7	2	19.59	40.87	60.46
60	6-May-23	PCSB	DLB	B31	RUN#3 RUN CAMERA TO CAPTURE TRSSV FLAPPER	718	340,634	3,100	RUN CAMERA TO CAPTURE FLAPPER	1.71	0.5	19.09	41.37	60.46
		PCSB												

PROCESS FLOW DIAGRAM



DIMENSION BID	PROCESS FLOW DIAGRAM		
		CLIENT	PETRONAS CARIGALI SDN. BHD.
		WELL NAME	Dulang B20
		JOB DESCRIPTION	Sand Cleanout
		REVISION	0

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.

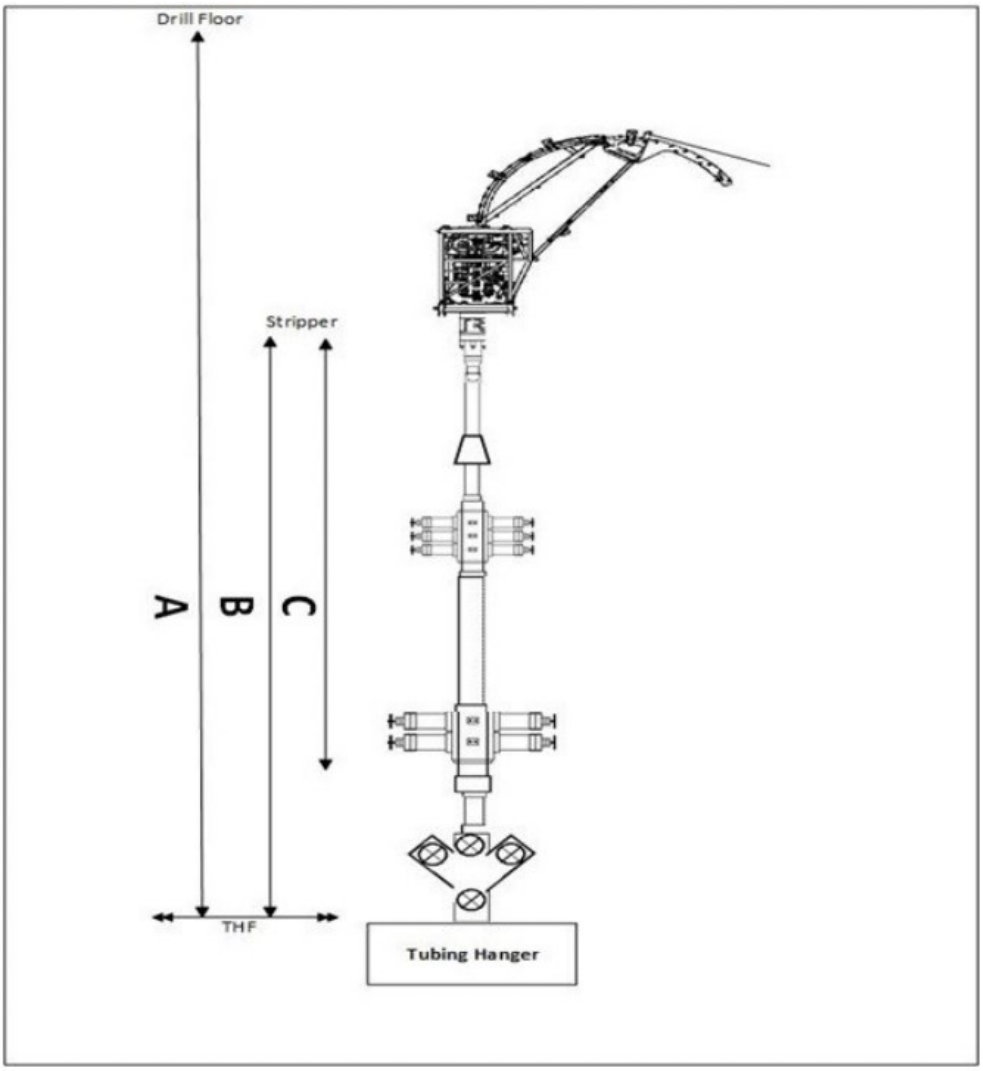
1. Spot the equipment accordingly to space availability, ensure reel position is aligned with the well.
2. Spot jacking frame at available space with sufficient height and crane capacity to rig up the injector head and gooseneck.
3. Rig up the 4” LP hoses from fluid storage tanks to batch mixer and single 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 / production system
9. Spot injector head assembly (c/w stripper) with jacking frame on top of wellhead area. Ensure the gooseneck is aligned with the reel position
10. Inspect the chain and gripper block condition and ensure the alignment is correct
11. Rig up the following hydraulic hoses:
    11.1. From CT Power Pack to CT Control Cabin
    11.2. From CT Power Pack to CT Injector hose reel
    11.3. From CT Control Cabin to CT Reel
    11.4. From CT Control Cabin to CT BOPs
    11.5. From CT Power Pack to Jacking Frame
12. Perform EMC 1 for all equipment. Start up and run all equipment for few minutes.
13. Jack up CT control cabin.
14. Function test both BOP rams.

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

    *Do not perform pull test more than 80% from CT Limit.
18. Install pressure test plate onto the CT connector.
19. Circulate the string with water until clean return is seen prior to proceed with pressure test CT Connector.
20. Pressure up the CT string to 5,000 psi gradually by 500 psi increment then hold for 10 minutes.

21. Open the needle valve to release the pressure slowly.
22. Flush coil to ensure there is no debris/metal inside the treating line or coil, and perform Coil pickling (7.5% HCL).

    Notes: All acid will be neutralized at surface line before flowback to system.
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”.

EQUIPMENT PRESSURE TESTING PROCEDURE

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

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

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

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

   *Step 4-8 can be neglected if pipe ram has been pressure tested prior to the job.
5. Place CT string across pipe ram then close the ram.
6. Open pipe ram equalizing valve then fill up the BOP slowly.
7. Close the equalizing valve and begin pressure test the pipe ram to 3,000 psi, hold for 10 minutes.
8. When the tests are complete, bleed off the pressure.

OPERATIONAL PROCEDURE

BULLHEADING ACTIVITY: INJECTIVITY TEST PRE – CTU OPERATION.

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.

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

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

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

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

2.3. Rig up CT package and surface treating line.

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

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

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

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

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

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

2.7.2. **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.

3. Prior start filling up with TIW, ensure to record THP and PCP and include in the daily report.

THP (psi)	PCP (psi)

4. Open well, bleed off tubing head pressure and casing head pressure to 0 psi or minimum value.
5. Pump and fill up tubing with TIW until full. Tubing volume calculated is 152 bbls.

Pumping Schedule to Fill up Tubing for Injectivity Test						
Stage	Description	Fluid	Vol (bbl)	Pump Rates (BPM)	Remarks	MASTP (psi)
1	**Fill-up completion volume**	TIW	152 bbls or till return is observed on surface	0.5- 1.0	152 bbls is calculated based on 1.5x completion volume.	**1,100**

6. Do not stop pumping after filling up completion. Proceed immediately with injectivity test. Log injectivity rate after the pumping pressure has stabilized over a 5min period.

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbl)	THP (psi)	CHP (psi)
0.50					
0.70					
1.00					
1.50					
2.00					
2.50					
3.00					

7. After complete injectivity test, share the result to town.

CT RUN#1: WELL, UNLOADING TO UNLOAD FILTER CAKE AND DEBRIS AT WELLBORE AREA (400 PSI DOWNHOLE DRAWDOWN)

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

8. Prepare 100bbls of Treated Injection Water, TIW as per recipe below (If required):

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:

d) Prepare Injection Water into the mixing tank.
e) Add ACM H2S Clear 200 into the tank and circulate the mixture.
f) 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.

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

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

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

9.3. Rig up CT package and surface treating line.

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

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

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

9.7. Install the Pull and Pressure Test Sub.

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

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

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

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

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

10. Make up 2.125" Upward Nozzle tool as per **BHA#1: 2.125" UPWARD NOZZLE** in **Appendix 1**.

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

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

Flow rates (bpm)	Pressure (psi)	Remark
0.3		
0.5		
0.7		
1.0		
1.1		
1.3		

12. Box up to connect the riser and prepare for pressure test.
13. Pick up CT and tag BHA with the stripper.
14. 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.

14.1. 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.

14.2. 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.

15. 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.

15.1. 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.

16. Upon successful test, bleed off the pressure in the CT stack up to zero through the pump-in sub.
17. Flush CT string empty with N2. Circulate returns direct to the flowback facility. DO NOT circulate into the wellbore.
18. Zero both depth counters (Orion and Mechanical) at reference point.

19. Confirm all wellhead and BOP valves are in open position via physical check.

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

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

CV Opening Turns	LMV Opening Turns

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

    19.4. Manipulate surface valve to the following position:

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

20. Start RIH BHA while pumping N2 at minimum permissible rate to first circulation point at depth **500m / 1,641ft MDTHF**, first circulation point is calculated based fluid level at this depth 500m / 1,641ft MDTHF, Hydrostatic pressure equal to Reservoir pressure. However based on nitrogen unloading analysis, first depth to increase Nitrogen rate to 400 scfm is at 200m/656 ft MDTHF. The last circulation point is at depth 1,120m / 3,675ft MDTHF to create underbalance condition of 400 psi.

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

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

    20.3. Maximum coil speed running in hole is **30-50 ft/min/ 9-10m/min.**

    20.4. Slow down coil speed to **10 ft/min/ 10m/min**, 50 ft / 15m before and after passing through completion accessories.

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

    20.6. Observe return all the times.

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

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

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

21. Once BHA reached 10m above First circulation point, stop coil 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

22. Continue RIH until 200-m MDTHF (first circulation point based on circa) and start pumping nitrogen with N2 rate 400 scf/min for 30 minutes while monitoring the returns on surface.

23. If there is fluid return on surface, continue to pump N2 and monitor debris return at flowback.

24. If there is no return of fluid on surface, proceed to run in hole 300-m deeper to continue N2 unloading (next circulation point).

25. Proceed to next circulation depth once observe no return fluid at surface as per table below:

Circulation Depth	N2 Rate (scf/min)
200m	400
500-m MDTHF (Hydrostatic Pressure = Pressure	400
800-m MDTHF	400
1,120-m MDTHF	400

26. Once observe constant fluid return to surface (at any circulation point), continuously unload and monitor return debris at surface.
27. Continue unload until continuous gaseous return at surface. (Based on circa, required at least 2 hour to unload all the fluid at depth 1,120m MDTHF.
28. Once continuous gaseous return is attained, POOH CT to surface while pumping N2 at minimal rate..
29. To confirm BHA on surface and above Tree valves, perform the following verification:
    29.1. Observed overpull once CT Connector tagged stripper.
    29.2. Number of turns to close the Tree valves is the same as opening turns.
30. Once verified BHA is above Tree valves and well is closed, bleed off pressure in coil and stack up.
31. Break out BHA and prepare for next CT Run's BHA configuration.
32. CT Supervisor/Operator to update pipe tracking management file and string file fatigue after each run and the file with town.

CT RUN#2: ACIDIZING ON ZONE E10/11, E12/13 & 14

NOTE : Ensure Tubing Pickling already been done prior for this operation.

1. Make up 2.125" Downward Nozzle tool as per **BHA#1: 2.125" DOWNWARD NOZZLE** in **Appendix 1**.

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

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

Flow rates (bpm)	Pressure (psi)	Remark
0.3		
0.5		
0.7		
1.0		
1.1		
1.3		

3. Box up to connect the riser and prepare for pressure test.
4. Pick up CT and tag BHA with the stripper.
5. 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.

   5.1. 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.

   5.2. 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.

6. 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.

   6.1. 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.

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

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

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

CV Opening Turns	LMV Opening Turns

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

9.4. Manipulate surface valve to the following position:

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

10. Start RIH BHA while pumping TIW until 2,320-m MDTHF (No-Go Nipple)

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

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

10.3. Maximum coil speed running in hole is **30-50 ft/min/ 9-10m/min.**

10.4. Slow down coil speed to **10 ft/min**, 50 ft/ 15m before and after passing through completion accessories.

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

10.6. Observe return all the times.

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

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

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

11. Once BHA reached 10m above No-go nipple, stop coil and conduct pull test of 10m/30ft and record the pulling weight both static and dynamic.

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

12. Continue RIH until FC tag No-go Nipple at 2,320m-MDTHF. After complete Tag, fill up tubing and completion volume as per below table before proceed with downhole injectivity test

Pumping Schedule to Fill up Tubing for Injectivity Test						
Stage	Description	Fluid	Vol (bbl)	Pump Rates (BPM)	Remarks	MASTP (psi)
1	**Fill-up completion volume**	TIW	152 bbls or till return is observed on surface	0.5- 1.0	152 bbls is calculated based on 1.5x completion volume.	**1,100**

13. Perform injectivity test as per below table.

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbl)	THP (psi)	CHP (psi)
0.50					
0.70					
1.00					
1.50					
2.00					

14. After completed injectivity test, proceed to prepare Pre-flush, Main Treatment, post flush and TIW as per chemical recipe below:

Pre-Flush Solvent			5,880	gals	140	bbls	Description
Products	Concentration		Volume				
Fresh Water	849	gptg	4,994	gals	118.90	bbls	Base Fluid
NE-Surf 200	4	gptg	24	gals	0.57	bbls	Non-Emulsifier
Ammonium Chloride	595	pptg	3,499	lbs			Clay Stabilizer
MESB MS 300	100	gptg	588	gals	14.00	bbls	Mutual Solvent

Acid Descaler (15% HCl)			5,880	gals	140	bbls	Description
Products	Concentration		Volume				
Fresh Water	419	gptg	2,465	gals	58.69	bbls	Base Fluid
ACM Corr 400	4	gptg	24	gals	0.57	bbls	Acid Corrosion Inhibitor
NE 500	4	gptg	24	gals	0.57	bbls	Non-Emulsifier
ACM Surf 210	3	gptg	18	gals	0.43	bbls	Surfactant
Ammonium Chloride	417	pptg	2,452	lbs			Clay Stabilizer
ACM Iron 300	25	pptg	147	lbs			Iron Sequestering
ACM Iron 200	15	gptg	88	gals	2.10	bbls	Iron Control
33% HCl	419	gptg	2,465	gals	58.69	bbls	Raw Acid
MS 300	100	gptg	588	gals	14.00	bbls	Mutual Solvent

Post-Flush with Fines Control Agent			5,880	gals	140	bbls	Description
Products	Concentration		Volume				
Fresh Water	891	gptg	5,241	gals	124.79	bbls	Base Fluid
NE-Surf 200	2	gptg	12	gals	0.29	bbls	Non-Emulsifier
Ammonium Chloride	595	pptg	3,499	lbs			Clay Stabilizer
Fine Contol Agent	10	gptg	59	gals	1.40	bbls	Fines Control
MS 300	50	gptg	294	gals	7.00	bbls	Mutual Solvent

15. After complete prepare all treatment fluid, proceed with pumping operation as per table below (the treatment volume is design for 2 ft penetration).

Pumping Schedule for E-Sand						
Stage	Description	Fluid	Vol (bbl)	Pump Rates (BPM)	Remarks	MASTP (psi)
1	Pre-Flush	**Solvent**	133	1.0	To remove hydrocarbon and pre-condition formation	1,100
2	Main Treatment	**15% HCl**	133	1.0	To remove calcite in wellbore and formation	1,100
3	Post Flush	**Solvent with Fine Control Agent**	25	1.0	To displace 15% HCl out Nozzle	1,000
Stop pump and soak 15% HCl for 2 hours						
After 2 hours, proceed to start pumping the remaining post flush and CT displacement						
4	Post Flush	**Solvent with Fine Control Agent**	108	1.0		1,000
5	Displacement	**TIW**	48 (CT volume + Wellbore Volume)	1.0	Spot Post Flush at penetration design	1,200
Once completed, POOH CT to surface while pumping 364bbls TIW, 5ft penetration into the formation.						

16. POOH CT to surface while pumping 364 bbls TIW thru CT (5ft penetration into the formation.)
17. Once CT at surface and complete pumping activity, shut in well (wait for well to stabilize).
18. CT Supervisor/Operator to update pipe tracking management file and string file fatigue after each run and the file with town.

BULLHEADING#3 INJECTIVITY TEST POST-ACIDIZING

1. Open CV/MV to proceed with Injectivity test through bullheading.
2. Proceed with pumping TIW to fill up completion volume prior injectivity test as per below table.

Pumping Schedule to Fill up Tubing for Injectivity Test						
Stage	Description	Fluid	Vol (bbl)	Pump Rates (BPM)	Remarks	MASTP (psi)
1	**Fill-up completion volume**	TIW	152 bbls or till return is observed on surface	0.5- 1.0	152 bbls is calculated based on 1.5x completion volume.	**1,100**

3. Do not stop pumping after filling up completion. Proceed immediately with injectivity test. Log injectivity rate after the pumping pressure has stabilized over a 5min period.
4. Continue injectivity testing rates up to MASTP.

Rate (bpm)	Pumping Pressure (psi)	Time (min)	Volume (bbl)	THP (psi)	CHP (psi)
0.50					
0.70					
1.00					
1.50					
2.00					
2.50					
3.00					

5. After complete injectivity test, proceed to share the result to town before proceed with next step.

APPENDIX I – BHA SCHEMATIC

BHA#1: UPWARD NOZZLE

DIMENSION BID

BHA DIAGRAM #1- 2.125" UPWARD NOZZLE

Client	Petronas Carigali	Well	D03S
Field	Dulang D	Min Restriction	2.75"
Job Type	Acidizing	BHP	
Job No.	CT Run#1	BHT	

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		2.225	0.80	0.8
	2-1/8" MHA Disconnect drop ball 3/4" Shear pressure 5,456 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5,000 psi	1.5 AMMT Box	1.5 AMMT Pin		2.125	2.30	3.1
	5 ft Straight Bar	1.5 AMMT Box	1.5 AMMT Pin		2.125	5.0	8.10
	3 ft Straight Bar	1.5 AMMT Box	1.5 AMMT Pin		2.125	3.0	11.10
	Upward Nozzle	1.5 AMMT Box			2.125	0.42	11.52

BHA LENGTH	11.52
MAXIMUM OD	2.125
MINIMUM ID	

Prepared by:	Muhammad Hafiz
Review by:	
Revision:	
Date:	

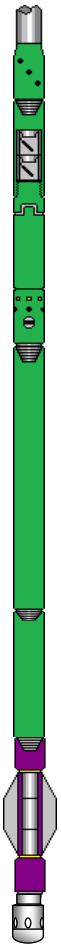
ADDITIONAL INFORMATION:

BHA#2: DOWNWARD NOZZLE

DIMENSION BID

BHA DIAGRAM #1- 2.125" DOWNWARD NOZZLE

Client	Petronas Carigali	Well	D03S
Field	Dulang D	Min Restriction	2.75"
Job Type	Acidizing	BHP	
Job No.	CT Run#2	BHT	

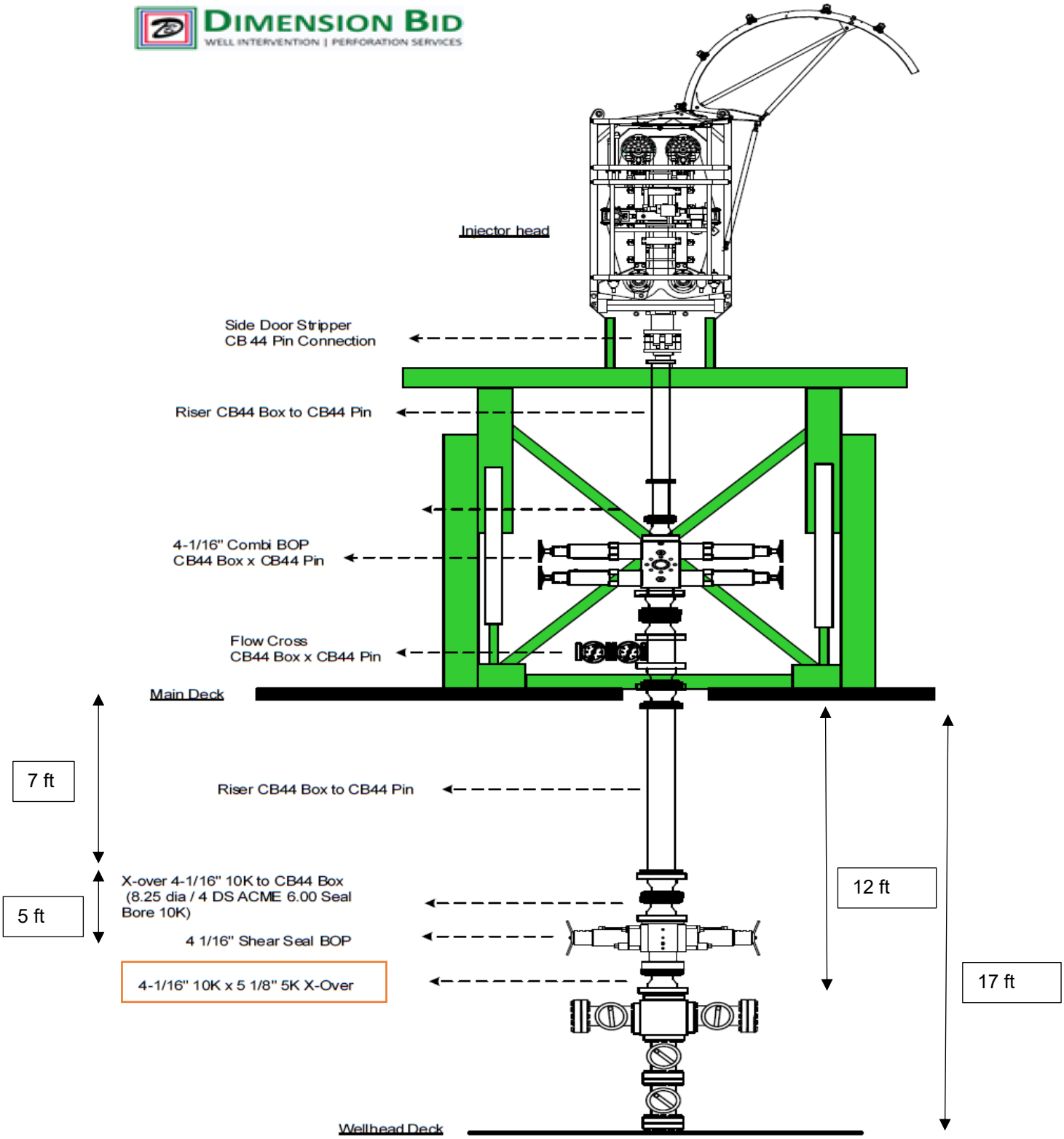
BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	External Dimple CT Connector	1.5" CT	1.5 AMMT Pin		2.225	0.80	0.8
	2-1/8" MHA Disconnect drop ball 3/4" Shear pressure 5,456 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5,000 psi	1.5 AMMT Box	1.5 AMMT Pin		2.125	2.30	3.1
	5 ft Straight Bar	1.5 AMMT Box	1.5 AMMT Pin		2.125	5.0	8.10
	3 ft Straight Bar	1.5 AMMT Box	1.5 AMMT Pin		2.125	3.0	11.10
	2.75 Fluted Centralizer	1.5 AMMT Box	1.5 AMMT Pin		2.750	1.0	12.10
	Downward Nozzle	1.5 AMMT Box			2.125	0.42	12.52

BHA LENGTH	12.52
MAXIMUM OD	2.750
MINIMUM ID	

Prepared by:	Muhammad Hafiz
Review by:	
Revision:	
Date:	

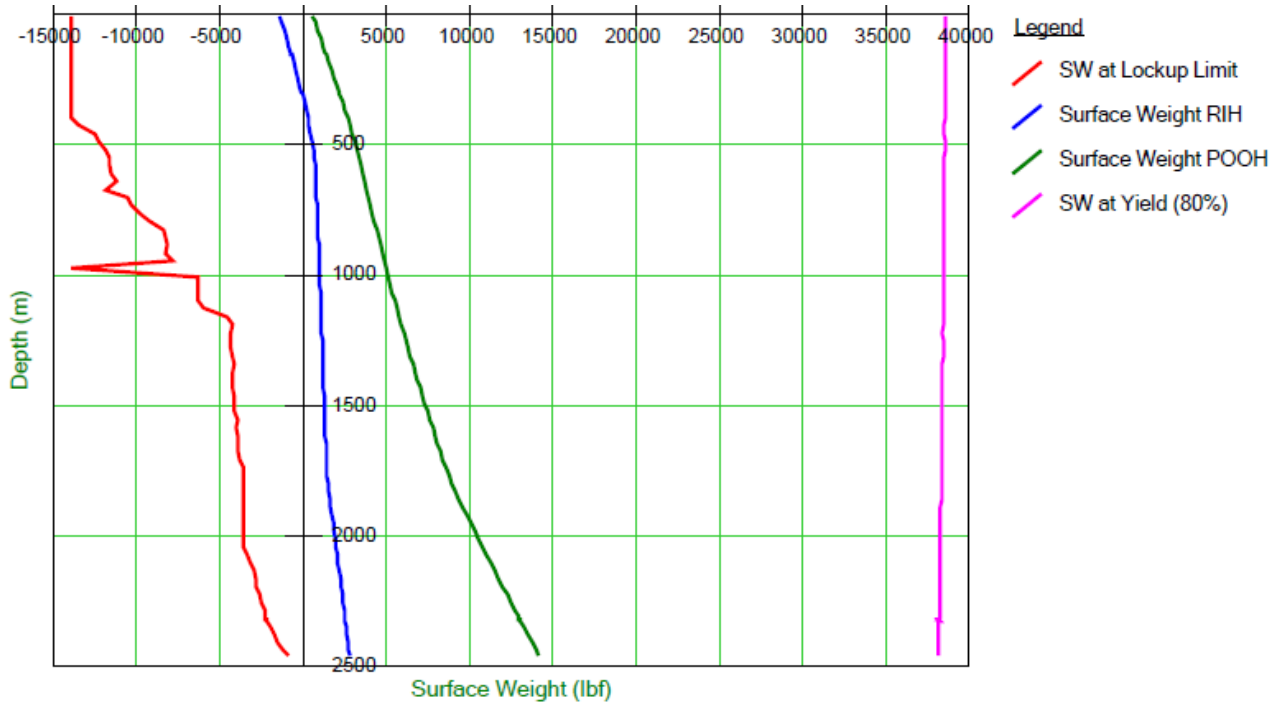
ADDITIONAL INFORMATION:

APPENDIX II – CT STACK UP

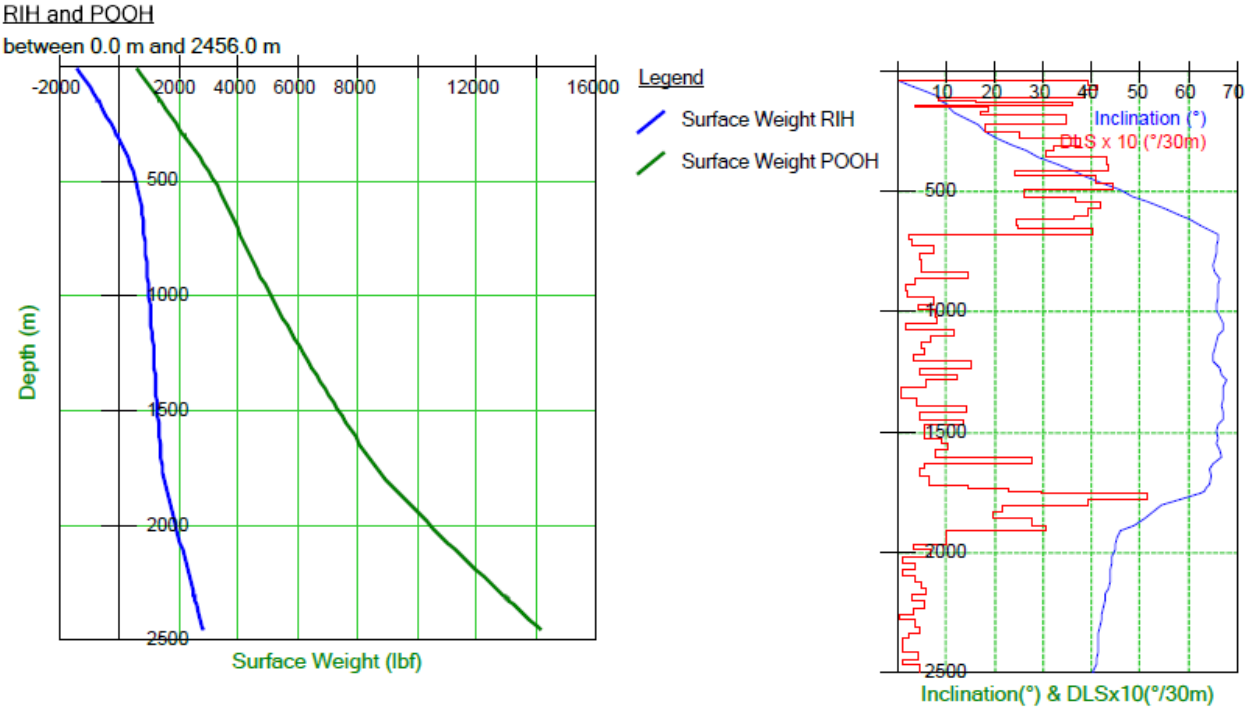


APPENDIX III – ORPHEUS SIMULATIONS

TUBING FORCE ANALYSIS 2,456m MDDF

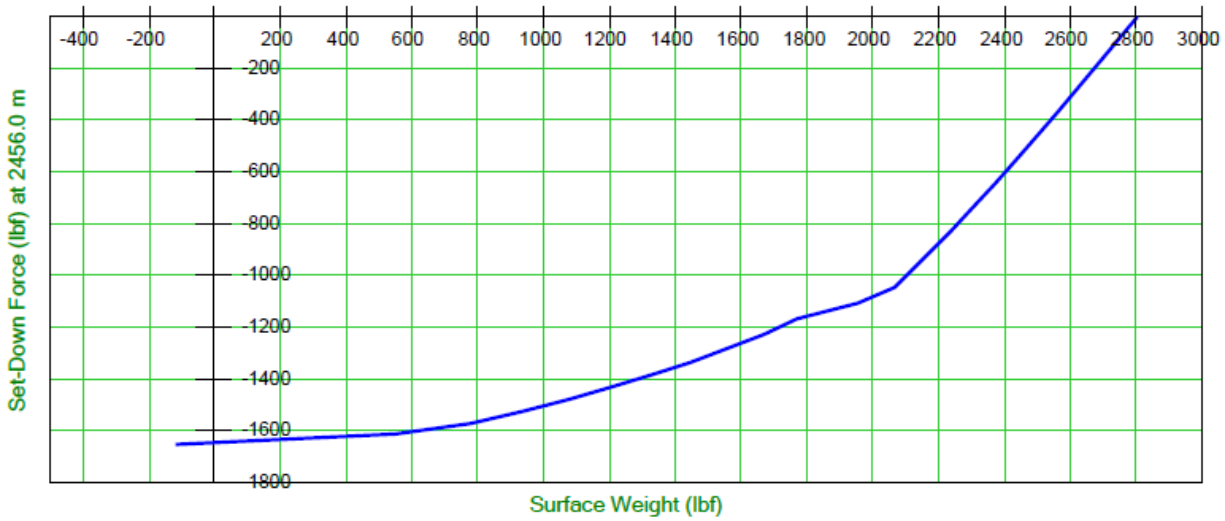


RIH & POOH WEIGHT



MAXIMUM STRING SET DOWN LIMIT

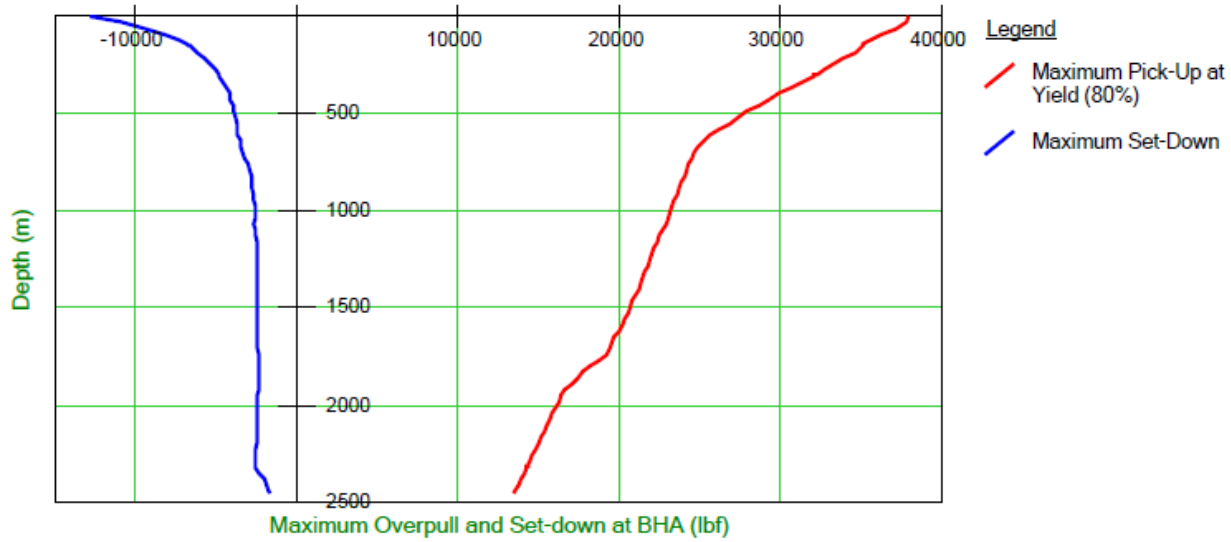
MD3 The available set-down force at 2456.0 m is -1653 lbf at the end of the string.
The weight indicator reading will be -830 lbf on surface.



MAXIMUM STRING PICK UP LIMIT

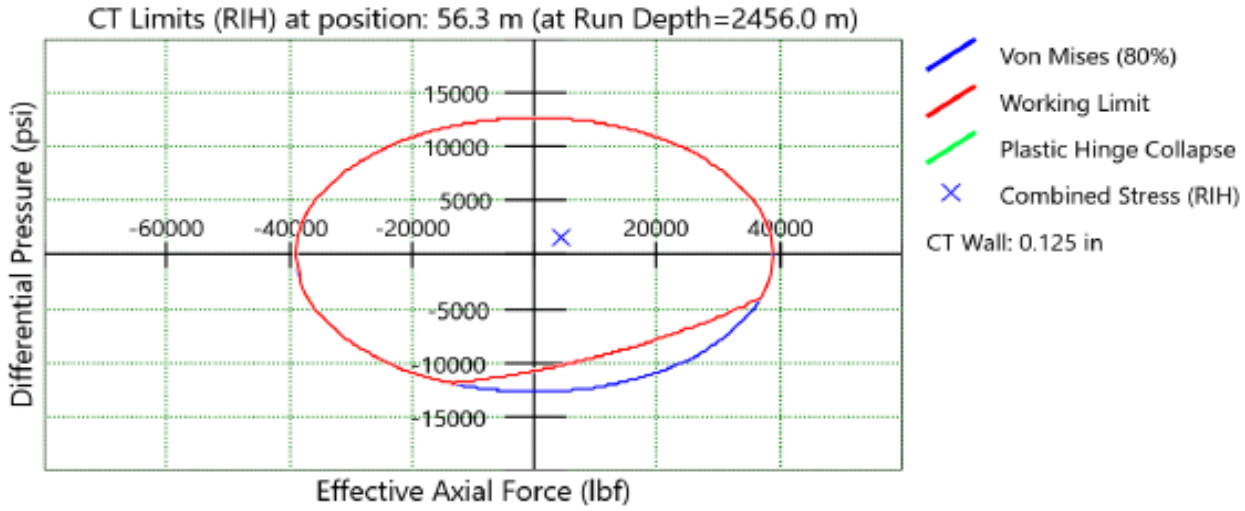
Calculations at 2456.0 m

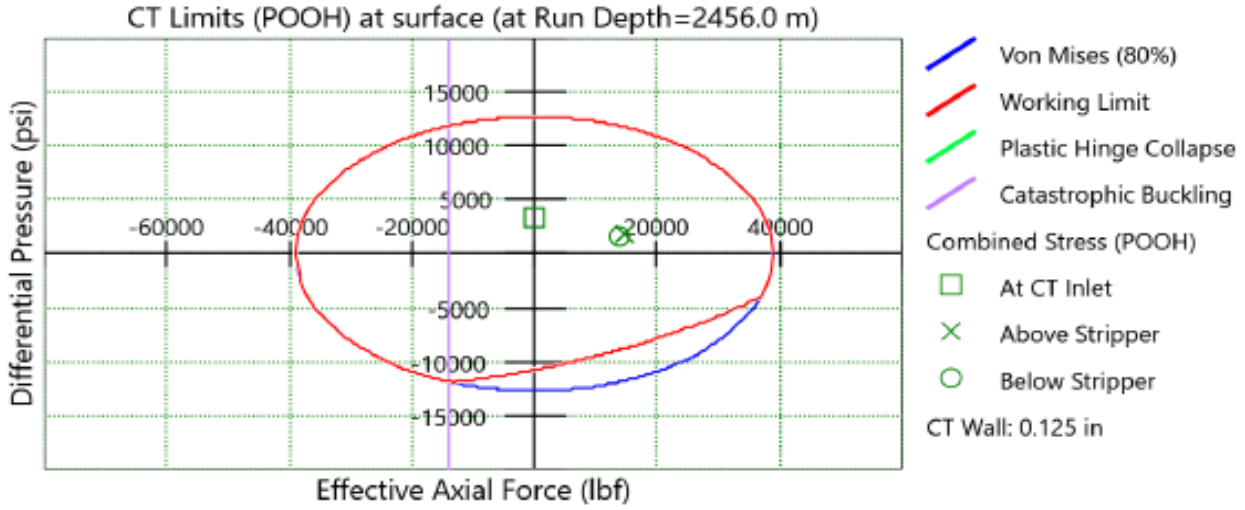
MD1 The available pick-up at 2456.0 m based on 80% of yield strength is 13506 lbf.
The weight indicator reading will then be 38167 lbf.



STRING LIMIT

CT Limits





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:

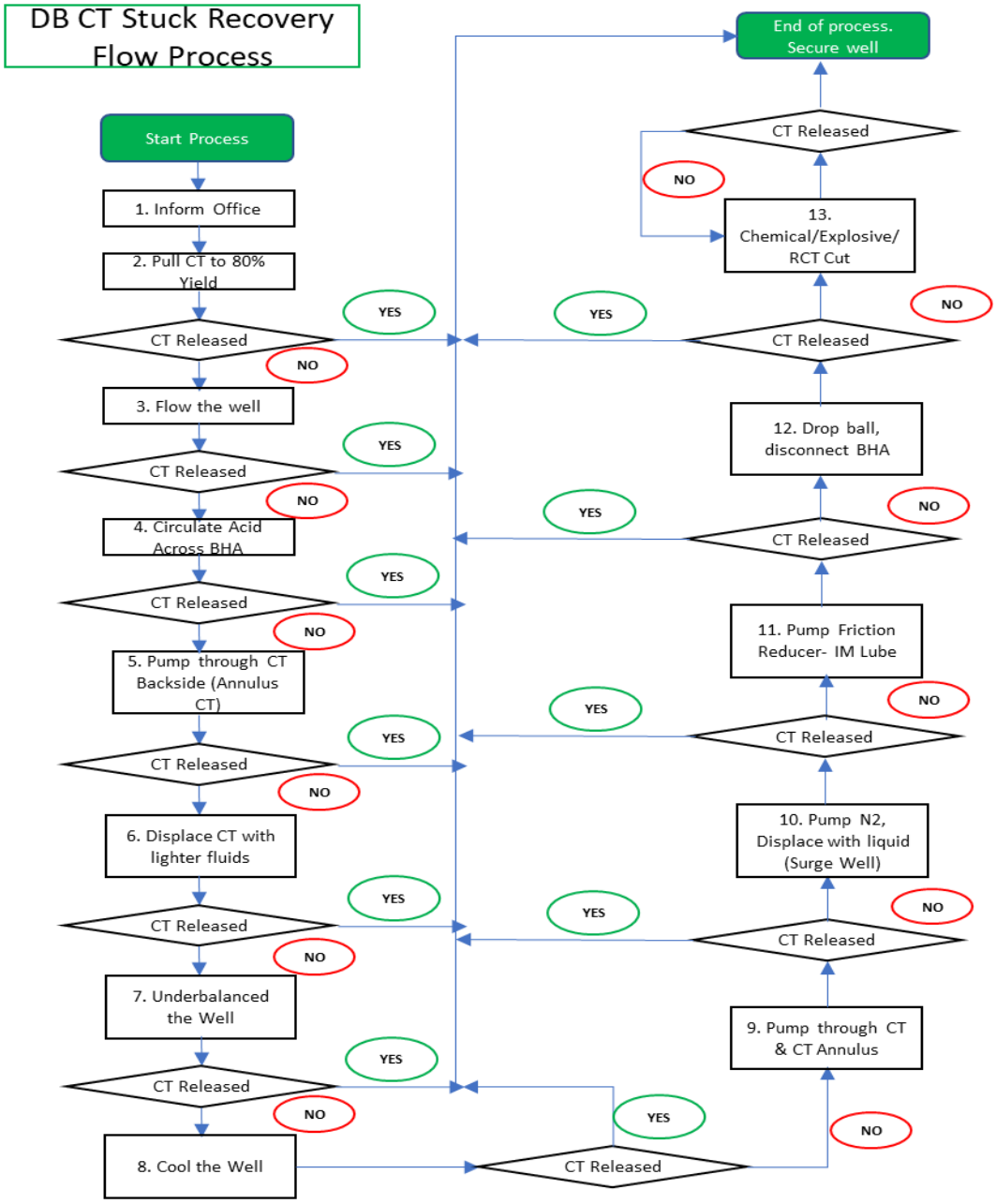
1. Inform the client representative of the situation.
2. Inform the Onshore Engineer.
3. From the information available, and taking into account the well conditions, try to determine the reason for the pipe/BHA being stuck.
4. Attempt to pull free by applying a steady pull to a maximum of 80% of the 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 External/Internal cutting operations.

STUCK CT COIL RECOVERY PROCESS



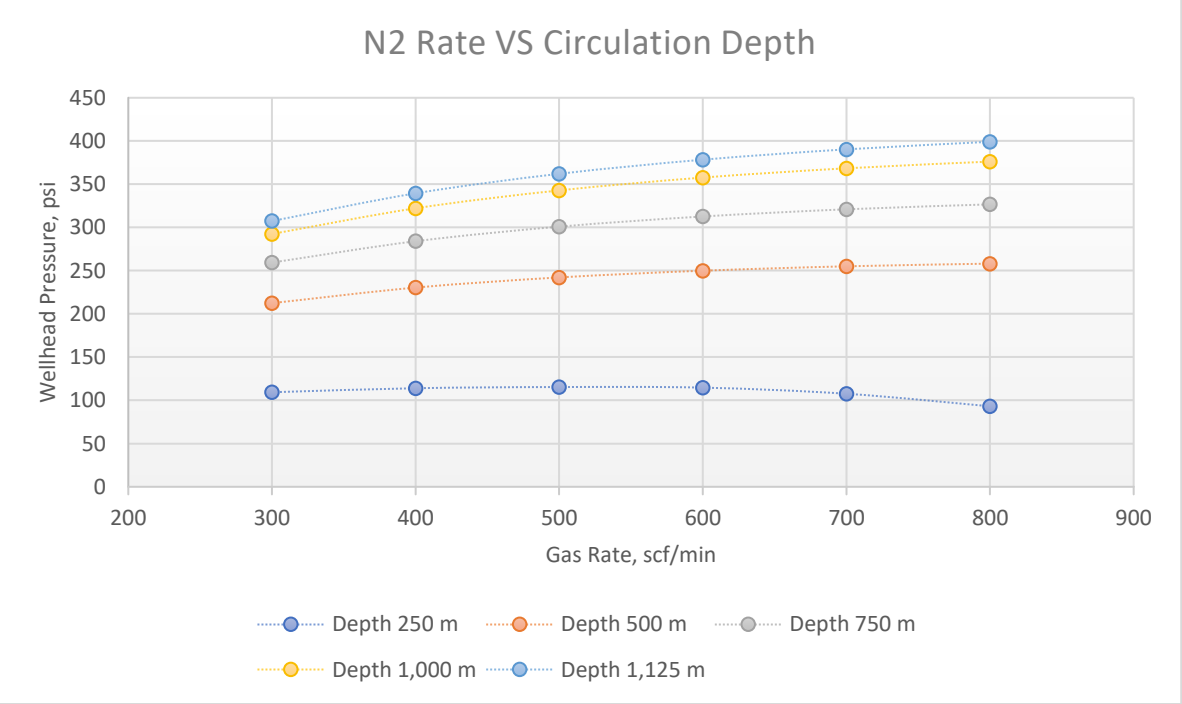
Precautionary Steps to avoid Stuck while Cleanout in Dual string Completion:

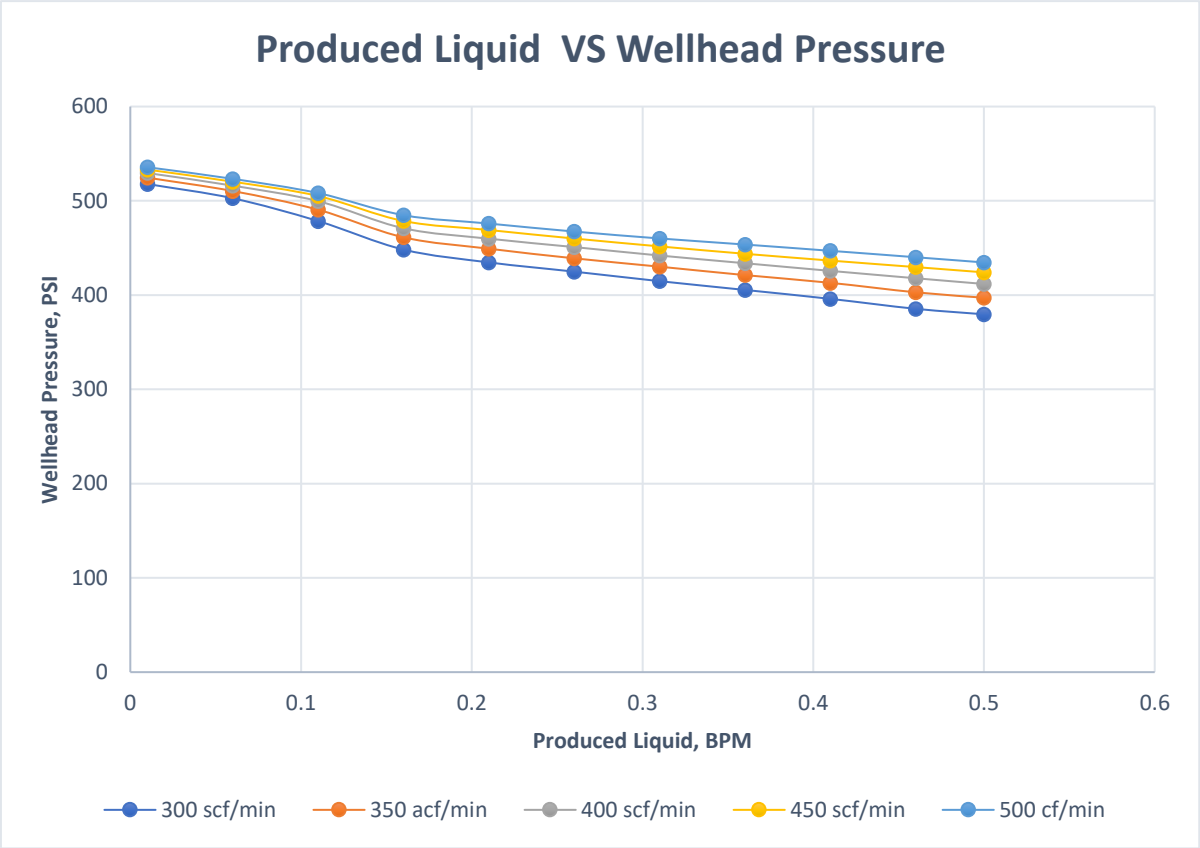
1) To monitor pressure trending all the times during operation and record for any abnormalities. If there is continue pressure increasing trend during cleanout, proceed to pick up coil to the previous pull test depth and perform flow rate test.
2) In the event of coil entangle on the Long string, proceed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

NITROGEN UNLOADING ANALYSIS

Circulation Depth

BHA Depth *m*	Completion Wellhead Pressure *psi g*	Perforation Pressure *psi g*	Completion Bottom Hole Pressure *psi g*	Circulation Point Pressure *psi g*	Workstring Injection Pressure *psi g*	Workstring Gooseneck Pressure *psi g*
90.0	0.0	1430.0	1548.8	28.4	645.2	119.2
190.0	72.7	1430.0	1548.8	133.3	654.4	185.3
290.0	130.4	1430.0	1548.8	234.7	679.3	275.0
390.0	175.2	1430.0	1548.8	329.1	712.6	361.0
490.0	209.4	1430.0	1548.8	411.3	747.9	436.4
590.0	234.2	1430.0	1548.8	477.9	779.8	498.1
690.0	250.7	1430.0	1548.8	527.2	804.7	544.7
790.0	264.6	1430.0	1548.8	571.3	828.0	586.4
890.0	278.0	1430.0	1548.8	615.2	852.2	627.4
990.0	290.7	1430.0	1548.8	659.0	877.1	667.7
1090.0	302.7	1430.0	1548.8	701.5	901.9	706.5
1190.0	314.8	1430.0	1548.8	745.9	928.5	746.4
1290.0	326.1	1430.0	1548.8	788.9	954.8	784.8
1390.0	336.7	1430.0	1548.8	830.5	980.7	821.7
1500.0	348.3	1430.0	1548.8	877.5	1010.4	862.8




Produced Liquid VS Wellhead Pressure
Wellhead Pressure, PSI
600
500
400
300
200
100
0
0
0.1
0.2
0.3
0.4
0.5
0.6
Produced Liquid, BPM
300 scf/min
350 acf/min
400 scf/min
450 scf/min
500 cf/min