DIMENSION BID

PETRONAS

DULANG B-16ST3
PLUG RETRIEVAL AND ZONE CHANGE

Revision: 3
Prepared for: Pravin Nair Venugopalan
Date Prepared: 14th February 2023
Well: B-16ST3
Field: Dulang Bravo
Operation Region: PMA

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DESIGN VERIFICATION

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REVIEWED BY DB CTS Technical Advisor	 Kung Yee Han	2/4/2023 Date
APPROVED BY DB CTS Operation Manager	 Aliff Amirul Hamzah bin Adenan	2/4/2023 Date
APPROVED BY PCSB Dulang Well Intervention Engineer	Pravin Nair Venugopalan	Date
APPROVED BY PCSB Technical Professional Well Intervention, PMA	M Izwan B Jalil	Date
APPROVED BY PCSB Head of Cluster 1 Well Intervention, PMA	M Asraf Nazri	Date

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

Open

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REVISION HISTORY

Rev. No	Section	Date	Revised By
0	All	14/2/2023	Atikah Nazifah Mustafa
1	1. Amendment to the decision tree 2. To include contingency step – VJB or cleanout in the event unable to latch on plug	10/3/2023	Atikah Nazifah Mustafa
2	1. Change in job procedure for RUN#2 CTU, added SPM Cleanout and soaking with Acid step	22/3/2023	Muhammad Hafiz Saharuddin
3	1. Revised CT String Use life	2/4/2023	Muhammad Hafiz Saharuddin

ACRONYM

Acronym	Abbreviation
BHA	Bottom Hole Assembly
RIH	Run In Hole
POOH	Pull Out Of Hole
HUD	Hang Up Depth
TCC	Tubing Clearance Check
ZSO	Zone Shut Off
SCO	Sand Clean Out
TIW	Treated Injection Water

TIT	Tubing Integrity Test
BOP	Blow Out Preventer
CT	Coiled Tubing
ID	Internal Diameter
MDDF	Measure Depth Drilling Floor
SSD	Sliding Side Door
MASTP	Maximum Allowable Surface Treating Pressure
STP	Surface Treating Pressure

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OBJECTIVES

The objective of this job is;

1. To perform retrieval of PXN plug at No-Go profile at **2860m-MDDF** and zone change at SSD #2 at depth **2703m- MDDF**

BACKGROUND

Dulang-B16 is a single oil producer which was completed on January 2002 with maximum deviation of 80.18 degree at 1,626m-MDDF. The B-16 well was incorporated with 2 7/8" tubing, 3 SSDs and a total depth of 3,223m - MDDF. Latest slickline intervention on December 2022 was executed to perform TCC using a 2.25" gauge ring but got hung up at depth 2789.3m-MDDF due to high well deviation. To cater the current condition, PCSB has engaged Dimension Bid to perform zone change out as well as retrieving the 2.31 PXN plug located at the XN-Nipple at depth 2,860m-MDDF.

WELL DATA

Input Parameter	Parameter Value
Field	Dulang Bravo
Max. Deviation (degrees)	80.18 degree @1,626m-MDDF
Min. Restriction (inch)	**2.313" @ 155m, 289m, 2795m MDDF** **2.250" (XN Nipple) @ 4625.33m MDDF**
Type of Fluid & Density	-
Top of Fluid	845m-WLTHF (December 2022)
Current Well Status	Effective Idle
Reservoir Pressure	1898 psig
Reservoir Temperature	211.9 deg F
Fracture Gradient	**Normal**
H_2S Content	N/A
CO_2 Content	N/A
Mercury, HG	N/A
Additional Information / Notes / Special Requirement:	

OPERATION SUMMARY

Item	Job Description	Remarks
A	**CT Operation**	1. CT RUN#1: Close SSD#2 using Hydraulic Shifting Tool at **2,703m-MDDF** 2. CT RUN#2: CT Solid Cleanout until top of PXN Plug at **2,860m-MDDF** 3. CT RUN#3: Drift run with 2.29 FC until top of plug at **2,860m-MDDF** 4. CT RUN#4: Cleanout Run using 1.81" VJB to clear any remaining debris at top of plug 5. CT RUN#5: PXN Plug Retrieval (Prong) using JDC 6. CT RUN#6: PXN Plug Retrieval (Body) using GS Pulling Tools
E	**CT Operation** **(Contingency)**	1. CONTINGENCY#1: Milling Operation to Last Held-up Depth 2. CONTINGENCY#2: CT Solid Cleanout until Top of PXN Plug or VJB at **2860M- MDDF** 3. CONTINGENCY#3: Impact Hammer with Blindbox to push plug to No-Go 4. CONTINGENCY#4: HPT & GRCCL Correlation and Dummy Tubing Cutter Run 5. CONTINGENCY#5: Tubing Cutter using SMART Blaster

WELL DIAGRAM

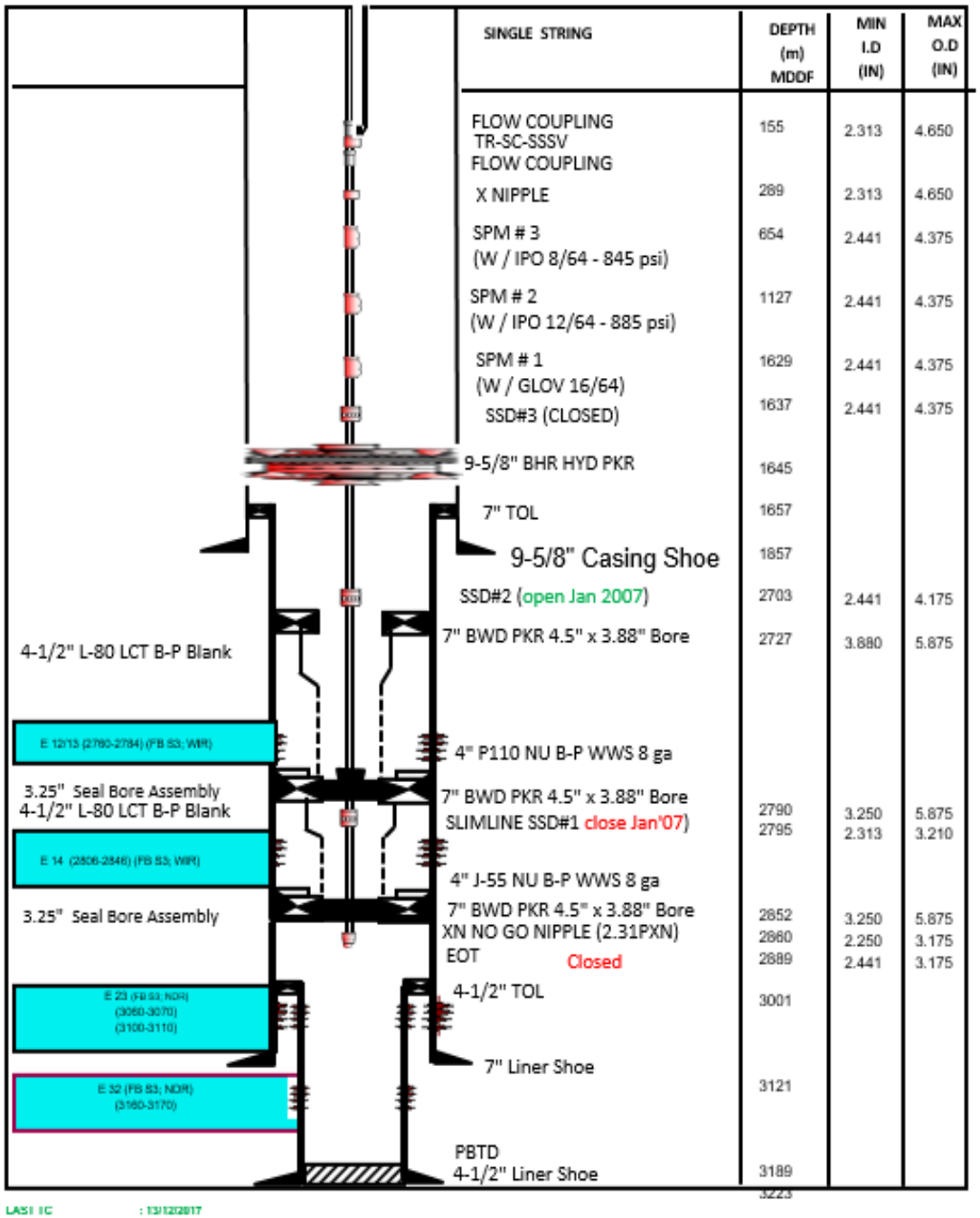
LAST UPDATE: Mac 2019

DULANG UNIT REVISIT I

B-16ST3 WELL COMPLETION DIAGRAM

RTIC

Well No.	: B-16ST3	Date	: 15 January 2002
Location	: BB	All Depth in	: m-MDDF
Wellhead	: Cooper cameron, 3-1/8",3000 psi	RKB	: 37.3m (to sea level)
Tubing	: 2 7/8", 6.4ppf, L-80, Vam Ace	Max Deviation : 80.18 @ 1626m-MDDF	



SINGLE STRING	DEPTH (m) MDDF	MIN I.D (IN)	MAX O.D (IN)
FLOW COUPLING TR-SC-SSSV FLOW COUPLING	155	2.313	4.650
X NIPPLE	289	2.313	4.650
SPM # 3 (W / IPO 8/64 - 845 psi)	654	2.441	4.375
SPM # 2 (W / IPO 12/64 - 885 psi)	1127	2.441	4.375
SPM # 1 (W / GLOV 16/64)	1629	2.441	4.375
SSD#3 (CLOSED)	1637	2.441	4.375
9-5/8" BHR HYD PKR	1645		
7" TOL	1657		
9-5/8" Casing Shoe	1857		
SSD#2 (open Jan 2007)	2703	2.441	4.175
7" BWD PKR 4.5" x 3.88" Bore	2727	3.880	5.875
4" P110 NU B-P WWS 8 ga			
7" BWD PKR 4.5" x 3.88" Bore	2790	3.250	5.875
SLIMLINE SSD#1 close Jan'07)	2795	2.313	3.210
4" J-55 NU B-P WWS 8 ga			
7" BWD PKR 4.5" x 3.88" Bore	2852	3.250	5.875
XN NO GO NIPPLE (2.31PXN)	2860	2.250	3.175
EOT Closed	2889	2.441	3.175
4-1/2" TOL	3001		
7" Liner Shoe	3121		
PBTD	3189		
4-1/2" Liner Shoe	3223		

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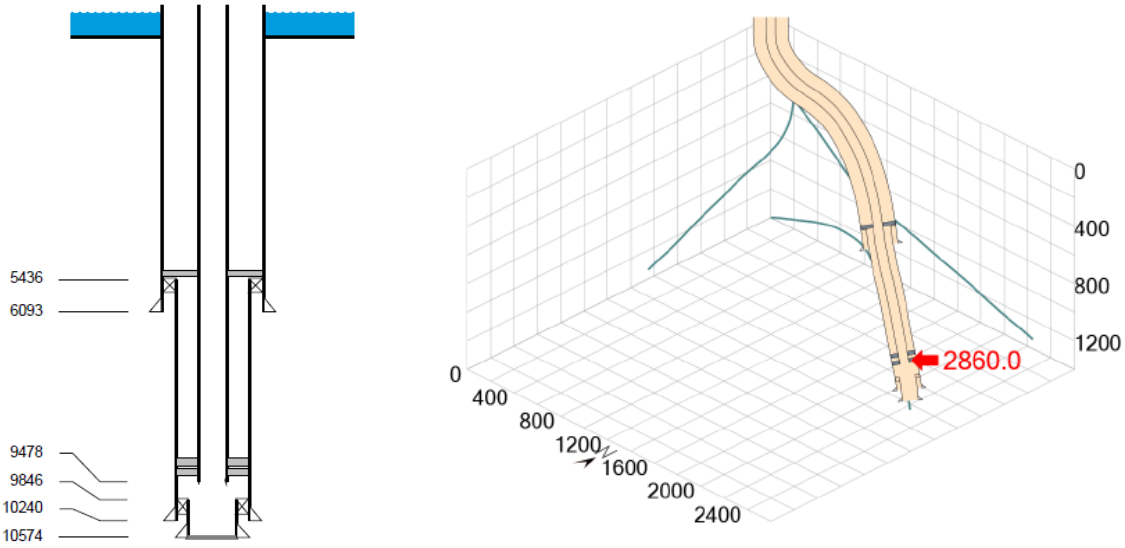
LAST TC : 13/12/2017
TYPE OF JOB : 1BCLH roller boogie MUD @1512m-WLTHP

Open

WELL 3D PLOT



Input Parameter	Parameter Value
Field	Dulang B16ST3
Trajectory Until Depth	3223m- MDDF
Max. Deviation (degrees)	80.18 degree at 1626m-MDDF
Min. Restriction (inch)	2.313” @ 155m, 289m, 2795m MDDF 2.250” (XN Nipple) @ 4625.33m MDDF

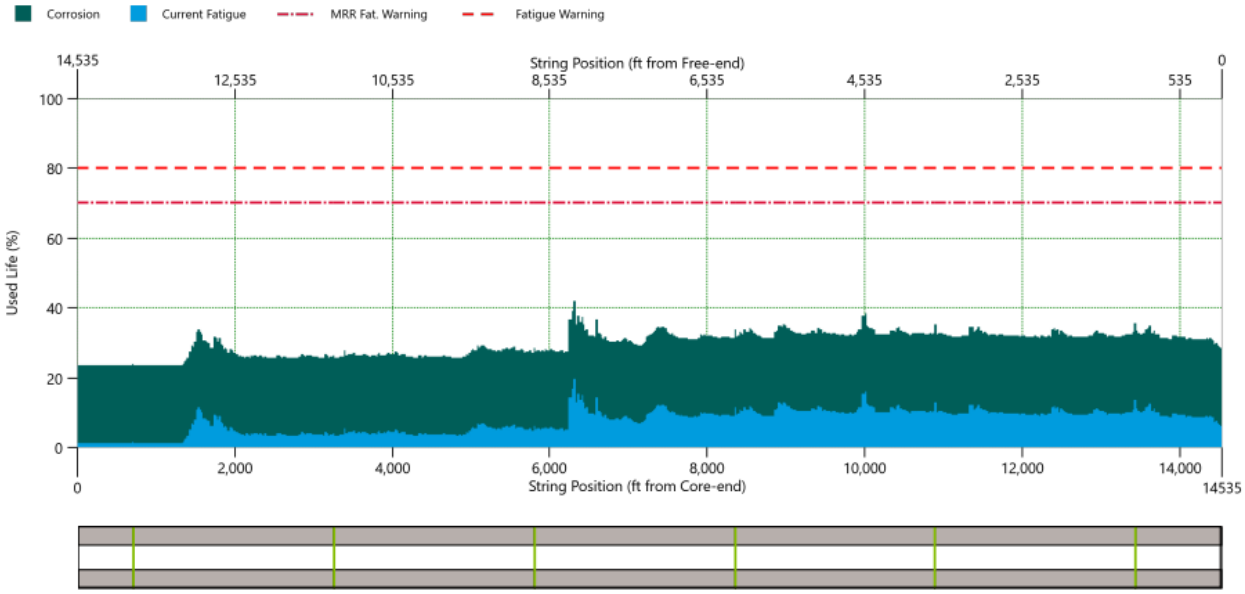
TREATMENT VOLUME

Annular Volume													
Type	External 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)	Barrel/lin (ft)	m	m	ft	ft	ft	
THF to top of PXN Plug	2 7/8	2.441					0.00579	15.30	2860	50	9384	**9333**	**54.02**
Acid Soaking	2 7/8	2.441					0.00579	2600	2860	8531	9384	**853**	**4.94**

COILED TUBING 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



CT STRING #39400 LATEST PIPE MANAGEMENT

Date	Client Name	Field Name	Well Num	Job type	Running ft ft	Cum. Run ft	Max CTV lb	Job Description	Job Fatigue %	Job Corrosion %	Max Fatigue	Cum. Corrosion %	Used String Life %
3-Sep-22	PCSB	ANGSI	D-04S	RUN#2: Depth Correlation & Stimulation	8265	147,420		15% HCl	1.46	0.5	15.51	18.8	34.31
5-Sep-22	PCSB	ANGSI	D-04S	RUN#3: Stimulation	11882	159,302		15% HCl	0.99	0.5	15.58	19.3	34.88
8-Sep-22	PCSB	ANGSI	D-04S	Cut 160ft coil	NA	NA	NA	TRIM COIL	0	0	15.58	19.3	34.88
9-Sep-22	PCSB	ANGSI	D-04S	Cut 200ft coil	NA	NA	NA	Pump CI & Purge Coil with N2	0	0	15.59	19.3	34.88
5-Oct-22	PCSB	ANGSI	D-02L	RUN#1: SCO	14390	173,692	15050	CT SAND CLEAN OUT	1.01	0.5	15.97	19.8	35.77
7-Oct-22	PCSB	ANGSI	D-02L	RUN#2: SCO	14791	188,483	34000	CT SAND CLEAN OUT	2.46	0.5	16.44	20.3	36.74
8-Oct-22	PCSB	ANGSI	D-02L	Cut 50ft coil	NA	NA	NA	TRIM COIL	0	0	16.44	20.3	36.74
13-Oct-22	PCSB	ANGSI	D-02L	RUN#3: SCO	19576	208,059	24000	CT SAND CLEAN OUT	6.04	0.5	16.7	20.3	37
16-Oct-22	PCSB	ANGSI-A	D-02L	RUN#4: SCO	18210	226,269	16200	CT SAND CLEAN OUT	3.79	0.5	19.18	20.8	39.98
16-Nov-22	PCSB	ANGSI		CUT COILED AT ANGSI ANDRA (505FT)	NA	NA	NA	TRIM COILED	0	0	19.18	20.3	39.48
18-Nov-22	PCSB	ANGSI	A-08L	CT RUN#1 SCALE CLEANOUT	13393	239,662	22,000	CT SCALE CLEANOUT	1.55	0.5	19.18	20.8	39.98
13-Dec-22	PCSB	OPEN YARD	NA	SPOOLING STORAGE	NA	NA	NA	SPOOLING FOR CHANGE REEL	0.33	0.5	19.5	21.3	40.16
13-Jan-23	PCSB	OPEN YARD	NA	1 MONTH STORAGE	NA	NA	NA	1 MONTH STORAGE	0	0.5	19.5	21.8	40.67
13-Feb-23	PCSB	OPEN YARD	NA	1 MONTH STORAGE	NA	NA	NA	1 MONTH STORAGE	0	0.5	19.5	22.3	41.8
6-Mar-23	PCSB	OPEN YARD	NA	P BALL 1",PRESSURE TEST COIL 7500PSI,PUMP INTERNAL CUP	NA	NA	NA	PRESSURE TEST COIL	0	0.07	19.5	22.37	41.87

Based on above pipe management;

- Current String Used Life is 41.87%
- Current Total Running Footage is 239,662 ft

Open

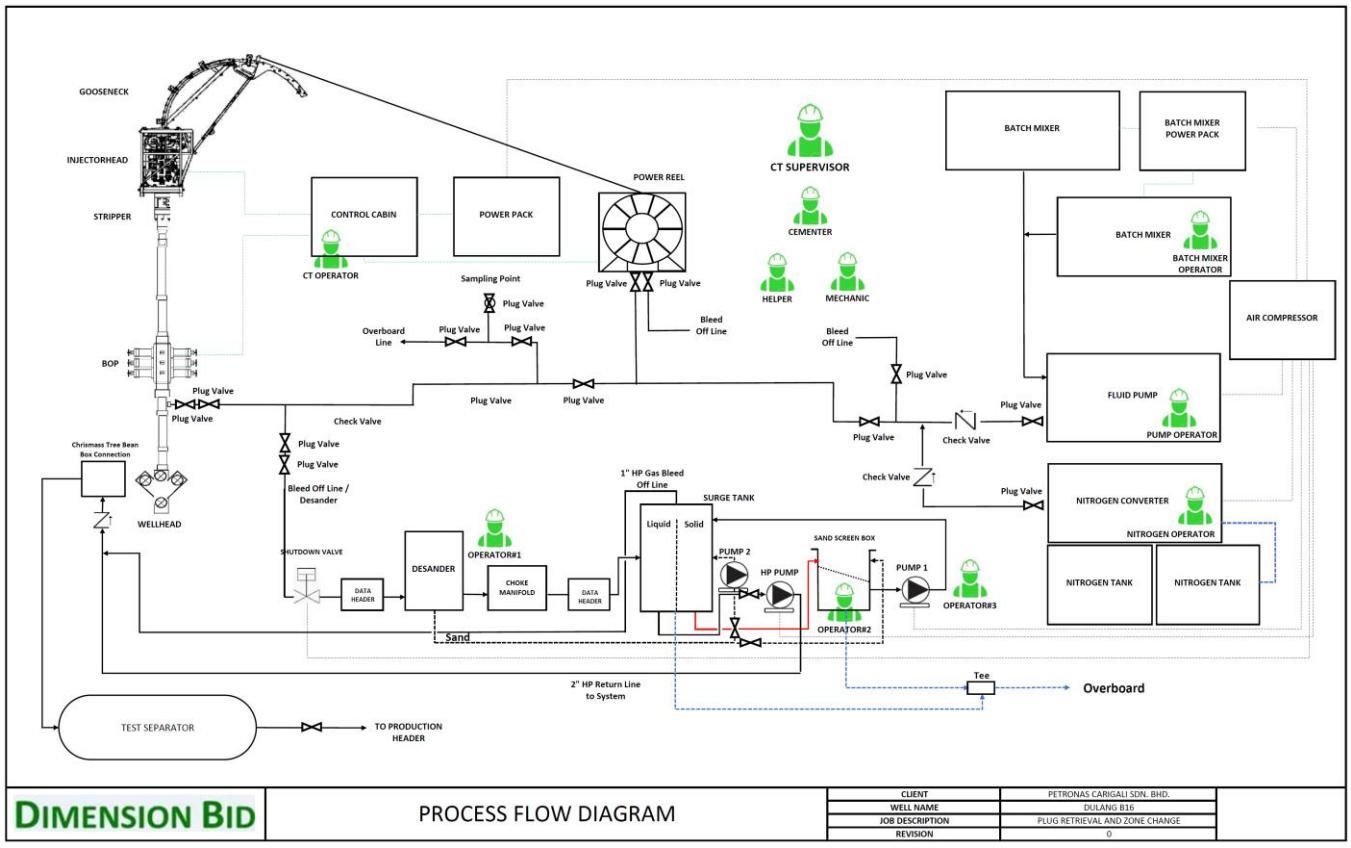
Based on Dimension Bid Standard Operating Procedure (SOP) of Pipe Management to junk the CT;

- **100%** of CT String Life reached
- Experienced two separate pinholes for the same CT String
- CT String exceed max working pressure

MAXIMUM ALLOWABLE SURFACE TREATING PRESSURE (MASTP)

Fluid	Fluid Density, ppg	Fluid Column until Mid Perf. TVD, ft	Hyd. Pressure, psi	Fracture Pressure, psi	STP, psi	80% MASTP, psi
Treated Injection Water	8.5	1,235	1,792	2,837	1,428	837

PROCESS FLOW DIAGRAM



Open

SAFETY OPERATIONAL PROCEDURES

Prior to commencement of the Coiled Tubing / Bull-heading 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 stops 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 string 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/FTHP), 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 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.

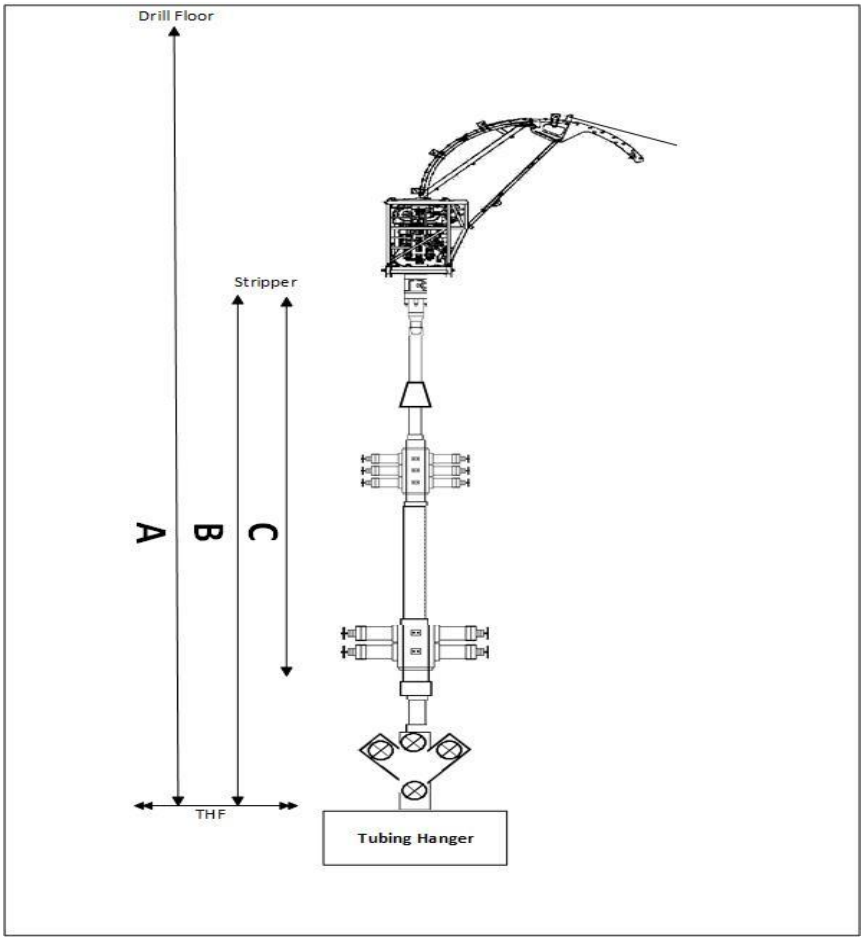
15. Install the stab-in-guide on the CT then stab the string into injector head.
16. Make up the CT connector and perform pull test at least 15,000 lbs as per DB SOP. This test to be recorded in OrionNET.

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

17. Install pressure test plate onto the CT connector.
18. Circulate the string with water until clean return is seen prior to proceed with pressure test CT Connector.
19. Pressure up the CT string to 6000 psi gradually by 500 psi increment then hold for 15 minutes. Acceptance Criteria for Low- and High-Pressure Test: No visible leaks and Pressure drop is less than 10% from Pressure Test Value over monitoring period after pressure stabilize.

Pressure test chart to be attached inside WIDR

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



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

24. 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**.

Open

GENERAL 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 string. 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.
   2.1. **Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 450 psi) over 5-minutes test interval after the pressure stabilizes.**
3. Increase pressure to 3000 psi and hold for 10 minutes. Inspect the lines for leaks and observe for any pressure drop.
   3.1. **Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 2,700 psi) over the 10- minutes test interval after the pressure stabilizes.**
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 3000 psi through the kill line, hold for 10 minutes. Inspect the lines for leaks and observe for any pressure drop. Refer to the acceptance criteria as in step 2 and 3.
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 3000 psi against Crown Valve, hold for 10 minutes.
3. Bleed off CT annulus pressure on wellhead stack-up to 1,500psi follow by bleeding of CT pressure to 0 psi to test the Double Flapper Check Valve and hold for 10 minutes. CT collapse pressure limit should not exceed 1,500 psi as per Dimension Bid SOP.
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 3000 psi, hold for 10 minutes.
8. When the tests are complete, bleed off the pressure.

OPERATIONAL PROCEDURE

All depths specified below are in m-MDDF (Drill floor to THF is 15.30-m as per well schematic)

BULLHEADING #1 TUBING COMMUNICATION TEST

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
Seq.	Product	Concentration		Volume	
1	Sea Water	994	gptg	4175	gal
2	ACM H2S Clear 200	2	gptg	8	gal
3	ACM BACT 200	2	gptg	8	gal
4	ACM OXYFREE 100	2	gptg	8	gal

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

2. Rig up the 4" LP hoses from fluid storage tanks to single pump unit.

3. Rig up 2" HP treating line as per DB Technical Standard from single pump to the wellhead. Ensure a bleed off line is installed in the line and secure it firmly.

4. Record shut in tubing head pressure (SITHP) and Production Casing Pressure (PCP).

SITHP, psi	PCP, psi

5. Confirm all wellhead and BOP valves are in open position via physical check.
   - 5.1. Prior to opening the wellhead valve, pressure up above master valves to a pressure equal to the expected shut-in wellhead pressure.
   - 5.2. Count wellhead valves turns while opening and record it the treatment report for reference in future.
   - 5.3. Manipulate surface valve to the following position:

Valve	Position
Reel Manifold	OPEN
Lower Master Valve	OPEN
Swab Valve	OPEN
Flow Cross Return Valve (CETCO Lines)	CLOSE
Wing Valve	CLOSE

6. Pump and fill up tubing with TIW, with maximum allowable pumping rate until tubing is full (1.5xTubing volume). Tubing volume calculated is 54 bbls.

7. Once desired volume reached and tubing head pressure is 0psi, continue to pressure up tubing to maximum 500 psi, starting with 0.3bpm and increase in stages if required. Once desired test pressure is achieved, stop pump and monitor the THP and PCP for 30 minutes. Record the reading in table below and include in Daily Report.

Time (min)	THP (psi)	PCP (psi)	Remarks
0			
5			
10			
15			
20			
25			
30			

NOTE: If unable to pressure up tubing to maximum 500psi with maximum allowable pumping rate, there is a possibility that rate of fluid losses to zone E12/13 is higher than rate of fluid being pumped into tubing. In this event, can reduce the test pressure to less than 500psi if possible.

8. Upon completion of tubing communication test, CLOSE LMV & CV and bleed off trapped tubing pressure above tree. Proceed with CT Run#1

CT OPERATION– RUN#1 CLOSE SSD#2 USING HYDRAULIC SHIFTING TOOL AT DEPTH 2,703M-MDDF

1. Rig up CT unit and surface line on Dulang B platform as per Site Visit Report:
   - 1.1. Review JHA and risk assessment with all personnel involve in the rig up operation. Please send a copy of JHA to Engineer in Charge.
   - 1.2. Lift up CT unit using crane and spot on platform.
   - 1.3. Rig up CT package and surface treating line.
   - 1.4. Rig up 2" kill line to BOP kill port.
   - 1.5. Rig up 2" flexible hose from pumping tee.
   - 1.6. Pig CT with treated injection water to ensure no debris is inside CT. Record CT volume in treatment report.
   - 1.7. Make up the CT End Connector.
   - 1.8. Install the Pull and Pressure Test Sub.
   - 1.9. Perform Pull Test on the CT End Connector to 15,000 lbf and record this in OrionNET.
   - 1.10. NOTE: Do not perform pull test more than 80% CT limit. Consult with town if require.
   - 1.11. Perform Pressure Test on CT End Connector. Pumping treated injection water through the CT string, apply low pressure test of 300 psi for 5 minutes and high-pressure test of 6,000 psi for 15 minutes after stabilization. Record the pressure test.
     - 1.11.1. 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.

     - 1.11.2. For high pressure:

       Acceptance criteria: No visible leaks. Pressure drop is less than 10% (above 5,400 psi) over the 15- minutes test interval after the pressure stabilizes.
2. Make up **BHA#1: 2.125" Bi-Directional Shifting Tools** in **Appendix I**.
3. Measure total BHA length: _____ ft
4. Testing Up Acting Hammer
   - 4.1. Install a pull test plate. Ensure free flow. Make sure the slinger (above impact hammer) is unloaded (neutral position).
   - 4.2. Start pumping with the idle rate. Record flow rate and circulating pressure.
   - 4.3. Slowly pick up BHA until pull test plate touched bottom of riser, and apply overpull (500 lbs or more, depends on Toolman recommendation) and let the tool impact until stable frequency of hammering is achieved (note in remark). Record flow rate and circulating pressure. Increase pump rate in stages and repeat function test.

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1.0		

Open

1.1		
1.2		
1.3		

4.4. Stop circulation & slowly unload the accelerator by lowering the pull test plate below the riser. Any trapped pressure shall release.
4.5. Tool may start to impact before the pressure bleeds off to zero once the tool returned in the neutral position. Remove the pull test plate from the BHA.

5. Testing Down Acting Hammer

5.1. Connect a ported bullnose to the bottom of the shifting tool to ensure free flow.
5.2. Start pumping with the idle rate. Record flow rate and pressure.
5.3. Slowly lower BHA until ported bullnose in contact with main deck. Then apply snubbing force (not more than 500 lbs) and let the tool impact until stable downward hammering frequency is achieved. Record flow rate and circulating pressure. Repeat the function test by increasing the pump rate in stages.

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1.0		
1.1		
1.2		
1.3		

5.4. Stop circulation & slowly unload the accelerator. Any trapped pressure shall release.
5.5. Tool may start to impact the pressure bleeds off to zero once the tool returned in the neutral position.

6. Perform function test of the Bi-Directional Shifting Tools (depends on toolman recommendation on site to use which key for first run) to determine at which pump rate and pressure the key starts to fully open (engage), when key starts to collapse. Record the data in the table below, circulating pressure to not exceed 5 ,000psi.

Flow rates (bpm)	Circulating 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		
1.5		

7. Pick up CT and tag the stripper with the BHA.
8. Make up the Injector Head and Stripper to the stack up.
9. CT stack up pressure test against wellhead swab valve. Pump 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.

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

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

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

    Acceptance criteria: Pressure drop is less than 10% (above 1,350 psi) over the 15- minute test interval after the pressure stabilizes. Observe for any pressure changes in the stack up. If the BHA check valve is not holding, proceed to replace the MHA; do not RIH with leaking check valve; repeat steps 9, and 10.
11. Upon successful test, bleed off the pressure in the CT stack up to zero through the pump-in sub.
12. Zero both depth counters at reference point.
13. Please ensure to record SITHP and PCP prior opening the well. Input in the daily operating report. Ensure to monitor and record these two parameters throughout our operation.

SITHP	PCP

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

    15.1. Prior to opening the wellhead valve, pressure up above master valves to a pressure equal to the expected shut-in wellhead pressure.
    15.2. Count wellhead valves turns while opening and record it the treatment report for reference in future.
    15.3. Manipulate surface valve to the following position:

Valve	Position
Reel Manifold	OPEN
Lower Master Valve	OPEN
Swab Valve	OPEN

Open

Flow Cross Return Valve (CETCO Lines)	OPEN
Wing Valve	CLOSE

15. Start RIH BHA to **2,713m/8,901ft MDDF** while pumping **TIW** at minimum rate permissible (@ 0.3bpm).

    16.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
    16.2. Conduct pull test and break circulation as per every 300m/1,000ft, with 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.

    16.3. Maximum CT speed RIH is 30-50 ft/min.
    16.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.
    16.5. Closely observe weight indicator in control cabin while RIH.
    16.6. Observe return all the times.
    16.7. Regularly inform WSS on job status at all times.
    16.8. Do not pump exceeding 5,000psi (surface treating pressure)
    16.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
    16.10. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.

16. Once BHA at 2,693m/8,835ft MDDF (10m above SSD), stop CT and conduct pull test of 10m/30ft with pumping rate 0.3BPM and record the pulling weight both static and dynamic

Depth (ft) MDDF	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

17. Slowly RIH until 10m below SSD#2 @ (2713m/8901ft MDDF)), slowly increase the pump rate to activate the Bi-Directional Shifting tool (referring to the surface function test). Record circulating pressure as baseline.

Shifting Tool Activation Pressure Range (psi)

18. Slowly pickup BHA at 1 - 5 ft/min and engage profile of sliding sleeve with hydraulic shifting tool (observe overpull and fluctuation in circulating pressure as an indicator that the shifting tool already engage with sliding sleeve). Flag CT with Flag#1

Flag Number	Colour
Flag #1	

19. If CT BHA already passed 10m above SSD#2 and still did not engage SSD#2, RIH BHA to 30m below SSD#2 and repeat step#17-#18. If after 2nd attempt, still unable to engage SSD#2 after applying maximum circulating pressure, POOH CT BHA to surface to check condition of shifting tool.

20. Increase overpull slowly (~500 lbs) and ensure pump rate is at optimum parameter to activate impact hammer at highest upward movement frequency maintain pulling weight while impact hammer upward force start shifting the sleeve upwards. If after 10 minutes, there is no progress with shifting the sleeve upwards, increase the overpull in stages by 500 lbs margin and repeat step (Do not exceed 80% of CT Pick up limit)

21. If CT pulling weight reached coil pick up limit, stop pump and wait for 10 minutes for key to collapse (return to normal hanging weight). RIH BHA 10m below and repeat attempt to close SSD.
22. Once the sleeve has been shifted fully upwards, a decreased in pulling weight shall be observed (back to initial pickup weight).
23. RIH back and repeat step 18 to 22 for at least 3 times **to confirm SSD#2 is fully shifted to close position, which is indicated by the shifting tool passing through without engaging the sleeve.**
24. Once confirmed SSD#2 is already closed, POOH and prepare for Run#2

CT Supervisor/Operator to update pipe tracking management file and string file fatigue after each run and share the file with town.

BULLHEADING #2 TUBING INTEGRITY TEST

1. Upon completion of CT Run#1, proceed with Tubing Integrity Test for a confirmation that SSD#2 has been closed
2. Prepare 100bbls of Treated Injection Water, TIW as per recipe below:

Treated Injection Water (TIW)				100	BBL
Seq.	Product	Concentration		Volume	
1	Sea Water	994	gptg	4175	gal
2	ACM H2S Clear 200	2	gptg	8	gal
3	ACM BACT 200	2	gptg	8	gal
4	ACM OXYFREE 100	2	gptg	8	gal

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

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

THP (psi)	PCP (psi)

4. 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 and constant return observed at surface. Tubing volume calculated is 54bbls.
6. Proceed to pressure up tubing to 500 psi.
7. Monitor the pressure for 30 minutes. If pressure holding, proceed with the rest of the job program. Record the reading in table below and include in Daily Report.

Time (min)	THP (psi)	PCP (psi)	Remarks
0			
5			
10			
15			

Open

20			
25			
30			

8. If tubing integrity passed, proceed to CT Run#2 for cleanout run. (THP maintains constant +/-500psi)
9. If tubing integrity failed where the pressure drop is more than 10% (Registered pressure = below 450 psi), consult town on way forward.

CT OPERATION – RUN#2 CT SOLID CLEANOUT UNTIL TOP OF PXN PLUG AT DEPTH 2,860M- MDDF

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

Treated Injection Water (TIW)				100	BBL	Description
Seq.	**Product**	**Concentration**		**Volume**		
1	Sea Water	994	gptg	4175	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	Metal Corrosion Inhibitor

Mixing Instruction:
1. Prepare Sea Water into the mixing tank.
2. Add ACM H2S Clear 200 into the tank and circulate the mixture.
3. Add ACM BACT 200 & ACM OXYFREE 100 into the tank and circulate

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	Sea Water	992	gptg	2,083	gal	Base Fluid
2	D801 Gel	40.5	pptg	85	lbs	Gelling Agent

Mixing Instruction:
1. Prepare Sea Water into 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. Make up **BHA#2 1-11/16" SpinCat Nozzle tool as per BHA#2: 1-11/16" SpinCat Nozzle** in Appendix I.
4. Measure total BHA length: _____ft

5. Perform function test of the SpinCat Nozzle to determine the pumping parameter that will activate rotation of Spincat. Record the data in the table below, do not exceed 5,000psi. Recommended flowrate is 0.7bpm to 1.3bpm.

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1.0		
1.1		
1.2		
1.3		

6. Repeat step 4 till 11 in Run#1 prior RIH
7. Start RIH BHA to **2,860m/9,383ft MDDF** while pumping TIW at minimum rate permissible.
   - 7.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
   - 7.2. 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.

   - 7.3. Maximum CT speed RIH is 30-50 ft/min.
   - 7.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.
   - 7.5. Closely observe weight indicator in control cabin while RIH.
   - 7.6. Observe return all the times.
   - 7.7. Regularly inform WSS on job status at all times.
   - 7.8. Do not exceed circulating pressure safety limits 5,000 psi.
   - 7.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
   - 7.10. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.
8. Once CT arrives 10m above slickline HUD (2779m MDDF), establish returns at surface. If no returns at surface, increase pumping rate to maximum permissible. If unable, introduce N_2.
9. Once returns established, RIH to **2,789.3m/9151ft MDDF** (25th November 2022) to start clean out (0.7 bpm expected for SpinCat to rotate). Refer below table for penetration stage.
   - 9.1. If SSD#2 confirmed closed, refer to table below, with changes being liquid rate of 1 bpm without N2.
   - 9.2. If SSD#2 is open, refer to table below, with liquid rate 0.8 bpm with 300 scf N_2

No.	Stage	Fluid	Liquid Rate	Total Liquid	N2 Rate (If require)	Nitrogen Consumption	CT Speed	Duration	Depth	Remarks
			BPM	Bbl	SCF/M	SCF/M	ft/min	Minute	m	

Open

1	CT at 10m above HUD	TIW	0.8	0	300	0	0	0	2779m (10m Above HUD)	Establish return on surface
2	Penetrating HUD/Fill	TIW	0.8	2.4	300	900	10	3	HUD + 10m	Monitor return & CT weight on surface
3	Circulate	Gel	0.8	5	300	1500	0	6.3	2799	Provide suspension to the fill and lift to surface
Pull Test 10m, continue pumping and wait till gel out on surface before penetrate to next HUD										
4	RIH to HUD and Penetrate HUD/Fill	TIW	0.8	2.4	300	900	10	3	HUD + 10m	Monitor return & CT weight on surface
5	Circulate	Gel	0.8	5	300	1500	0	6.3	2809	Provide suspension to the fill and lift to surface
6	RIH to HUD and Penetrate HUD/Fill	TIW	0.8	2.4	300	900	10	3	HUD + 10m	Monitor return & CT weight on surface
7	Circulate	Gel	0.8	5	300	1500	0	6.3	2819	Provide suspension to the fill and lift to surface
8	RIH to HUD and Penetrate HUD/Fill	TIW	0.8	2.4	300	900	10	3	HUD + 10m	Monitor return & CT weight on surface
9	Circulate	Gel	0.8	5	300	1500	0	6.3	2829	Provide suspension to the fill and lift to surface
Pull Test 10m, continue pumping and wait till gel out on surface before penetrate to next HUD										
10	RIH to HUD and Penetrate HUD/Fill	TIW	0.8	2.4	300	900	10	3	HUD + 10m	Monitor return & CT weight on surface
11	Circulate	Gel	0.8	5	300	1500	0	6.3	2839	Provide suspension to the fill and lift to surface
12	RIH to HUD and Penetrate HUD/Fill	TIW	0.8	2.4	300	900	10	3	HUD + 10m	Monitor return & CT weight on surface
13	Circulate	Gel	0.8	5	300	1500	0	6.3	2849	Provide suspension to the fill and lift to surface
14	RIH to HUD and Penetrate HUD/Fill	TIW	0.8	2.4	300	900	10	3.1	HUD + 11m	Monitor return & CT weight on surface

15	Circulate	Gel	0.8	5	300	1500	0	6.3	2860	Provide suspension to the fill and lift to surface
Pull Test 10m, continue pumping and wait till gel out on surface before penetrate to next HUD										

10. If CT encountered hard obstruction before PXN plug @ (2,860m MDDF), proceed to pick up BHA 10m above the obstruction and circulate at least 2x bottom up with TIW until clear return is observe on surface before proceed with the following steps.

10.1. RIH and slack off BHA not exceeding 500lbf (surface) on top of the obstruction and attempt to jet on the obstruction. If no success proceeds to mix 10bbls of 15% HCl acid and Neutralization Fluid as per the following recipe:

15% HCl (Main Treatment)				**10**	**BBL**	**Description**
Seq.	**Product**	**Concentration**		**Volume**		
1	Sea 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 sea water
2. Add additives as per above sequence
3. Agitate until mixture is homogenous

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

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

10.2. Upon completion mixing 15% HCl acid, proceed to jet 5bbls of 15% HCl on top of the obstruction while attempt to pass through the obstruction.

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

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

11. Once completed with D801 system circulation at top of PXN Plug **2860m/9383ft- MDDF** depth, proceed to bottoms up with 2x CT/Tubing annulus volume with TIW.

12. Proceed to spot a total of 3 bbls of 15% HCl and chase with TIW with CT stationary at 2,860m MDDF. Once 0.25bbls out of nozzle (start timer), immediately start POOH CT to safe depth at 2,000m MDDF while keeping pumping rate constant at 0.3bpm.

13. In the event of unable to perform continuous circulation (pump down or fluid not enough), proceed to pick up the BHA to safe depth 1,000m/3,281ft MDDF.

14. **Once At 2,000m- MDDF**, increase pump rate to 0.8 bpm to continuously circulate TIW while soaking is undergoing.

15. After 1 hour acid soaking, RIH BHA again to top of PXN plug while pumping TIW at high rate (refer to 9.1 or 9.2 pumping rate) and displace the acid.

16. Once BHA reached top of PXN plug, pick up BHA 10m and proceed to perform circulation bottoms up with TIW as per CIRCA analysis for 3 hours.

17. After complete bottoms up, RIH again and tag at least twice at top of PXN plug. (Do not slack off more than 500 lbf – surface)

18. Flag CT at surface, Flag#2 and reset mechanical and Orion depth counter accordingly before proceed to wiper trip.

Flag Number	Colour
Flag #2	

19. Start to wiper trip CT until surface. Refer wiper trip speed as below.

19.1. If SSD#2 is open condition, proceed with 0.8 bpm and 300 scf for pump rate

19.2. If SSD#2 is close condition, proceed with 1.0 bpm for pump rate

Depth From (m)	Depth To (m)	Wiper Trip Speed (ft/min)
2,860	2,200	30
2,200	1,200	15
1,200	Surface	30

20. Once CT complete wiper trip to surface, RIH back to depth 1,635m/5,365ft MDDF, follow as per table below for job acid soaking and jetting across the SPM#1-3

No.	Stage	Fluid Used	Fluids		Tripping			Totals		Stage	RIH	Time
			BPM	SCFM	From (ft)	To (ft)	ft/min	BBLS	GAL N2	bbls	ft/min	hr
1	RIH to 20 ft below SPM#1	FLUID 1 - TSW	0.3		0	5,365	30.0	53.7			30.0	
2	Pump 2 bbls of 15% HCL	FLUID 2 - Acid	0.3		5,365	5,365	0.0	2.0		2.0		
3	Pump TSW to Displace the HCL, untill 0.5 bbls of acid exit nozzle	FLUID 1 - TSW	0.7		5,365	5,365	0.0	21.5		21.5		
4	Pick up BHA while spot HCL across the SPM#3	FLUID 1 - TSW	0.3		5,365	5,020	30.0	3.5			30.0	
5	Pick up BHA to safe depth while soaking	FLUID 1 - TSW	0.3		5,020	4,500	30.0	5.2			30.0	
6	Soaking Acid for 30 minutes				4,500	4,500						0.5
7	High Jetting, reciprocate downward	FLUID 1 - TSW	1.0		4,500	5,365	20.0	43.3			20.0	
8	High Jetting, reciprocate upward	FLUID 1 - TSW	1.0		5,365	5,200	20.0	8.3			20.0	
9	Pick up BHA to 10 ft below SPM#2	FLUID 1 - TSW	0.3		5,200	3,785	30.0	14.3			30.0	
10	Pump 2 bbls of 15% HCL	FLUID 2 - Acid	0.3		3,785	3,785	0.0	2.0		2.0		
11	Pump TSW to Displace the HCL, untill 0.5 bbls of acid exit nozzle	FLUID 1 - TSW	0.7		3,785	3,785	0.0	21.5		21.5		
12	Pick up BHA while spot HCL across the SPM#2	FLUID 1 - TSW	0.3		3,785	3,429	30.0	3.5			30.0	
13	Pick up BHA to safe depth while soaking	FLUID 1 - TSW	0.3		3,429	3,200	30.0	2.3			30.0	
14	Soaking Acid for 30 minutes		0.0		3,200	3,200		0.0				0.5
15	High Jetting, reciprocate downward	FLUID 1 - TSW	1.0		3,200	3,785	20.0	28.8			20.0	
16	High Jetting, reciprocate upward	FLUID 1 - TSW	1.0		3,785	3,600	20.0	8.8			20.0	
17	Pick up BHA to 10 ft below SPM#1	FLUID 1 - TSW	0.3		3,600	2,307	30.0	13.0			30.0	
18	Pump 2 bbls of 15% HCL	FLUID 2 - Acid	0.7		2,307	2,297	0.0	2.0		2.0		
19	Pump TSW to Displace the HCL, untill 0.5 bbls of acid exit nozzle	FLUID 1 - TSW	0.3		2,307	2,307	0.0	21.5		21.5		
20	Pick up BHA while spot HCL across the SPM#1	FLUID 1 - TSW	0.3		2,307	1,952	30.0	3.5			30.0	
21	Pick up BHA to safe depth while soaking	FLUID 1 - TSW	0.3		1,952	1,700	30.0	2.5			30.0	

Open

22	Soaking Acid for 30 minutes				1,700	1,700						0.5
23	High Jetting, reciprocate downward	FLUID 1 - TSW			1,700	2,307	20.0				20.0	
24	High Jetting, reciprocate upward	FLUID 1 - TSW			2,307	2,197	20.0				20.0	
25	POOH to surface	FLUID 1 - TSW	0.3		2,197	0	30.0	22.0			30.0	

21. Once complete as per table above, POOH CT to surface.
22. Once CT on surface, close well and bleed off pressure in CT and stack up.
23. CT Supervisor/Operator to update pipe tracking management file and string file fatigue after each run and the file with town.

Visually check on CT string to ensure no abnormalities on CT surface especially near the CT connector.

Open

CT OPERATION – RUN#3 DRIFT RUN WITH 2.29 FC UNTIL TOP OF PXN PLUG @2,860M-MDDF

1. Make up **BHA#3: 1.69" MultiJet Nozzle C/W 2.29" Fluted Centralizer as per Appendix I**.
2. Measure total BHA length: _____ft
3. Perform function test of the MultiJet nozzle to determine pump rate & pressure parameter for the tool to operate. Record the data in the table below, do not exceed 5,000psi.

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1		
1.1		
1.2		
1.3		

4. Repeat step 4 till 11 in Run#1 prior RIH
5. Start RIH BHA to **2,860m/9,383ft MDDF** while pumping **TIW** at minimum rate permissible.
   - 5.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III
   - 5.2. 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.

   - 5.3. Maximum CT speed running in hole is **30-50 ft/min.**
   - 5.4. Slow down CT speed to **10 ft/min**, 50 ft before and after passing through completion accessories.
   - 5.5. Closely observe weight indicator in control cabin while running in hole.
   - 5.6. Observe return all the times.
   - 5.7. Regularly inform WSS on job status at all times.
   - 5.8. Do not exceed circulating pressure safety limits **5,000 psi.**
   - 5.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
   - 5.10. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.
6. Once BHA at 10m above top of PXN plug **(2860m/9,350ft MDDF),** conduct pull test of at least 10m/30ft or more. Record the weight both static and dynamic as per below table.

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

7. Once complete pull test, slow down CT speed to 10 ft/min, and continue to RIH to tag the PXN plug while pumping at minimum permissible rate, 0.3 bpm. Closely observe weight indicator in Control Cabin while RIH, do not slack off more than 1000lbf (surface) in the event encounter any HUD.
8. Once PXN plug is tagged, proceed to pick up BHA 10m/30ft above the HUD, and perform at least 2 times tag to verify the PXN plug depth. (Do not slack off more than 1000lbf – surface)
9. If CT encountered hard obstruction before reach target depth, proceed to pick up BHA 10m above the obstruction and circulate at least 2x bottom up with TIW until clear return is observe on surface before proceed with the following steps. Introduce nitrogen in the event of return is unable to establish on surface.

    9.1. RIH and slack off BHA not exceeding 500lbf (surface) on top of the obstruction and attempt to jet on the obstruction. If no success proceeds to mix 10bbls of 15% HCl acid and Neutralization Fluid as per the following recipe:

15% HCl (Main Treatment)				**10**	**BBL**	**Description**
Seq.	**Product**	**Concentration**		**Volume**		
1	Sea 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 sea water
2. Add additives as per above sequence
3. Agitate until mixture is homogenous

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

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

    9.2. Upon completion of 15% HCl acid mixing, proceed to jet 5bbls of 15% HCl on top of the obstruction while attempt to pass through the obstruction.

    9.3. If no success during jetting HCl acid, proceed to spot another 5bbls of 15% HCl on top of obstruction and pick up BHA at least 550m above the obstruction depth to soak the acid for 2 hours. After

completed soaking, proceed to RIH to pass through the obstruction while pumping nitrified TIW. If unable to penetrate consult town, flag CT and POOH to surface

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

10. Once tagged is done, proceed to POOH CT to surface.
11. Once CT on surface, close well and bleed off pressure in CT and stack up.
12. CT Supervisor/Operator to update pipe tracking management file and string file fatigue after each run and the file with town.

Visually check on CT string to ensure no abnormalities on CT surface especially near the CT connector.

CT OPERATION– RUN#4 CLEANOUT RUN USING 1.81" VJB TO CLEAR REMAINING DEBRIS ABOVE PXN PLUG

1. Make up **BHA#4: 1.81" Venturi Junk Basket in Appendix I**.
2. Measure total BHA length: _____ft
3. Perform function test of the Venturi Junk Basket to determine pump rate & pressure parameter for the tool. Record the data in the table below, do not exceed 5,000psi

Flowrate (bpm)	Circulating Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1		
1.1		
1.2		
1.3		

4. Repeat step from 4 till 11 in Run#1 prior making up and open the well.
5. Start RIH BHA to 2,860m/9,383ft MDDF without pumping.

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

5.2. Conduct pull test as per for every 300m (1,000ft), use CT Fatigue graph as reference. Break circulation at idle rate with 2 bbls.

Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.

5.3. Maximum CT speed running in hole is 30-50 ft/min.

5.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.

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

5.6. Observe return all the times.

5.7. Regularly inform WSS on job status at all times.

5.8. Do not exceed circulating pressure safety limits 5,000 psi.

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

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

6. Monitor CT weight all the time, do not slack off more than 500lbf (surface) in the event encounter any HUD.

7. Stop BHA movement at 10m above top of PXN plug, 2,850m/9,351ft MDDF and perform pull test. Record the weight as per table below

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

8. Once completed pull test, continue to RIH to dry tag top of PXN plug at 2,860m/9,383ft MDDF. Do not slack off more than 500lbs (surface). Pick up CT, and repeat step 7 again one more time.

9. Pick up BHA to 30ft (2,850m/9351ft MDDF) to neutral CT weight and start increase pump rate to 1.0 bpm.

10. Upon completion pumping and observe stable circulating pressure, start RIH to 1ft above top of plug

11. Stop BHA 1ft above top of plug and continue to pump with pump rate 1.0bpm.

12. Monitor circulating pressure while pumping.

NOTE: Circulating pressure to not exceed 4000psi. Pressure will increase when the VJB is full.

13. Once pressure has increased to 4000psi or is constant for 30 minutes, pick up BHA 30ft above top of plug and observe for 20 minutes.

13.1. If circulating pressure drop, repeat step 9 to 13.

13.2. If circulating pressure constant, stop pump and POOH to surface.

13.3. If circulating pressure reached maximum 4000psi, stop pump and POOH to surface.

14. Once CT on surface, close well and bleed off pressure in CT and stack up. Wellpro specialist to open the junk basket and send photo of the debris recovered to town. Consult with town on whether require to re-run VJB or can proceed with P-prong retrieval.

15. CT Supervisor/Operator to update pipe tracking management file and string file fatigue after each run and the file with town.

Visually check on CT string to ensure no abnormalities on CT surface especially near the CT connector

CT OPERATION– RUN#5 PXN PRONG RETRIEVAL USING JDC

1. Make up **BHA#5: 1.765" Flow Release JDC C/W 2.125" Stabilizer in Appendix I**

2. Perform function test of the JDC flow release tool to determine pump rate & pressure parameter for the grapples to retract (release mode). Record the data in the table below, do not exceed 5,000psi

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		

Open

0.75		
1		

3. Repeat step 4 till 11 in Run#1 prior to RIH
4. Start RIH BHA to 2,860m/9,383ft MDDF without pumping
   - 4.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
   - 4.2. Conduct pull test as per for every 300m (1,000ft), use CT Fatigue graph as reference. Break circulation every 1000 ft @ 0.3 bpm.

   Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.

   - 4.3. Maximum CT speed running in hole is 30-50 ft/min.
   - 4.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.
   - 4.5. Closely observe weight indicator in control cabin while running in hole.
   - 4.6. Observe return all the times.
   - 4.7. Regularly inform WSS on job status at all times.
   - 4.8. Do not exceed circulating pressure safety limits 5,000 psi.
   - 4.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
   - 4.10. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT at specified speed.
5. Prior reaching 10m above top of prong at 2850m- MDDF, monitor and record RW and PW for the string.

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

6. Once complete pull test, continue RIH slowly at 10 ft/min and tag the PXN prong without pumping (Do not slack off more than 1000lbf – surface). Increase pumping rate to release mode, and pick up BHA 10ft above plug, to neutral CT weight and station BHA.
7. Start pumping to fill up tubing. Once return observed at surface, close flow cross on surface
   - 7.1. To create overbalanced condition, pressure up tubing until 240 psi. Refer table below:

No	Input Parameter	Pressure (psig)	Remarks
1	Reservoir Pressure	1898	
2	Estimated bottom hole pressure	1856	$P_{Reservoir} - HP_{Bottom\ plug\ until\ reservoir\ pressure}$
3	Estimated pressure acting on top of plug	1820	Hydrostatic Pressure

8. Once overbalanced achieved, increase pumping rate as per function test on surface to activate JDC FR pulling tool
9. RIH 1ft/min and slowly tag top of prong with <1,000 lbs (surface), stop pumping and pick up CT. Apply overpull with CT in stages (500-1000 lbs). If observed overpull, indication that JDC successfully latched

to prong, and observed changes to surface pressure, indication that prong has been released from the plug body, POOH BHA to surface.

10. If required to do another pumping at the backside of the CT, refer to the CT limit operating window at the Orpheus.
11. If there were no overpull observed and are no changes to surface pressure, there is possibility that JDC was unsuccessful to latch and retrieve prong: -
    - 11.1. Increase set down weight
        - 11.1.1. Pick up BHA 10m above top of prong, start pump as per function test on surface to activate JDC FR tool.
        - 11.1.2. RIH to top of prong and apply an increase set down weight of 1,000-1,800lbf (surface), and stop pumping.
        - 11.1.3. Pick up BHA to observe if there is any over pull to indicate prong is successfully latched. Check for the 2 parameters as confirmation that prong has been released from PXN plug. Continue with step 12. If no positive indication, continue with 11.2
    - 11.2. RIH BHA at a higher running speed
        - 11.2.1. Pick up BHA to 15m above prong.
        - 11.2.2. RIH to top of prong at a higher speed than normal (actual number to be confirm at site by Wellpro Supervisor and agreed on by PCSB WSS) to latch onto the prong (pumps off).
        - 11.2.3. Pick up BHA to observe if there is any over pull to indicate prong is successfully latched. Continue with step 12 If no positive indication, continue with 11.3
    - 11.3. Clean top of PXN prong from any possible debris and sand
        - 11.3.1. Pick up BHA 10ft above the prong
        - 11.3.2. Slowly RIH to top of prong while pumping 5bbls of D801 system at maximum pumping rate
        - 11.3.3. Proceed to bottoms up with 10bbls TIW
        - 11.3.4. Upon completion bottom up, stop pumping and re-attempt to latch by repeating step 10 and 11 **(If necessary)**
12. Over pull to establish engagement of retrieval tool (Approximately 2,000 to 3,000lbs – surface) without firing the jars. If prong is free, POOH BHA to surface
13. If the prong is still unable to free, RIH to set down weight to reset the jar and take over-pull (approximately 3,000lbs – surface) and fire the jars – noting time of detent delay mechanism. Repeat this step up to 5 times with increasing overpull (DO NOT exceed 80% CT Pick up limit)

    Wellpro Tool Specialist to advise based on onsite parameters

    NOTE: If pumping has been performed, shut down pumps and allow pressure to stabilise and bleed before picking up.
14. If prong still unable to be latched and retrieved after multiple attempts, consult town for way forward.
15. If town agreed to re-attempt, proceed to increase over-pull in 1,000lbf increments (surface) – noting time of delay (i.e., shorter delay for larger over-pull), until the prong is free. Never exceed 80% of the yield of the CTU string or 80% of the maximum allowable over-pull on the B.H.A., whichever is the less.
16. If the tool string is released (normal string weight is observed on weight gauge), proceed POOH to surface.
17. If the tool string remains unreleased, slack off weight to re-cock the jar and repeat an over pull indicated in the table below;

Weight Gauge Reading before over pull (lbf)	Over pull at surface (lbf)	Weight Gauge Reading after over pull (lbf)	Pipe movement (ft)	No. of Attempt
	5,000			
	6,000			
	7,000			
	8,000			
	9,000			
	10,000			

Table of parameters during jarring

18. When the prong is 'free, it is not recommended to slack off weight back down on the prong.
19. POOH BHA to surface.
20. Once CT at surface, box up and release the prong from overshot tool.

Visually check on CT string to ensure no abnormalities on CT surface especially near the CT connector.

CT OPERATION– RUN#6 PXN PLUG BODY RETRIEVAL USING GS PULLING TOOLS

1. Make up **BHA#6: 2.22" GS Retrieval Tool C/W 2.125" Stabilizer in Appendix I**
2. Perform function test of the GS Pulling Tools to determine pump rate & pressure parameter for the grapples to retract. Record the data in the table below, do not exceed 5,000psi

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.75		
1		

3. Repeat step 4 till 11 in Run#1 prior RIH
4. Start RIH BHA to 2,860m/9,383ft MDDF without pumping
   - 4.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
   - 4.2. Conduct pull test as per for every 300m (1,000ft), use CT Fatigue graph as reference. Break circulation every 1000 ft at idle rate.

   Ensure the CT Fatigue graph is available at location before RIH. Record RIH, Hanging and POOH weight in treatment report.

   - 4.3. Maximum CT speed running in hole is 30-50 ft/min.
   - 4.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.
   - 4.5. Closely observe weight indicator in control cabin while running in hole.

4.6. Observe return all the times.

4.7. Regularly inform WSS on job status at all times.

4.8. Do not exceed circulating pressure safety limits 5,000 psi.

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

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

5. Prior reaching top of plug body (2,850m/9,351ft MDDF) (approximately 10m above top of plug), monitor and record RW and PW for the string.

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

6. Once complete pull test, continue RIH slowly at 10 ft/min and tag the PXN plug body without pumping (Do not slack off more than 1000lbf (surface).

6.1. If when pick up CT, observed overpull, that means GS has latched to PXN fish neck. Commence fishing of PXN plug as per step 11.

6.2. If when pick up CT did not observe overpull, GS did not latch to PXN fish neck. Pick up BHA to 10ft above to neutral CT weight and proceed to next step.

7. Increase pumping rate as per function test on surface to activate GS Pulling Tools

8. RIH and slowly tag top of plug body, stop pumping and observe if there is any overpull to indicate that the plug is successfully latched

9. If the plug body is unable to latch: -

9.1. Increase set down weight

9.1.1. Pick up BHA 10m above top of plug, start pump as per function test on surface to activate JDC FR tool

9.1.2. RIH to top of plug and apply an increase set down weight of 1,000-1,800lbf (surface) and stop pumping

9.1.3. Pick up BHA to observe if there is any over pull to indicate plug body is successfully latched. Continue with step 12

9.2. RIH BHA at a higher running speed

9.2.1. Pick up BHA to 15m above plug body. RIH to top of plug body at a higher speed than normal (actual number to be confirm at site by Wellpro Supervisor and agreed on by PCSB WSS) in an attempt to get the GS latched onto the plug body

9.2.2. Pick up BHA to observe if there is any over pull to indicate plug body is successfully latched. Continue with step 12

9.3. Clean top of PXN plug body from any possible debris and sand

9.3.1. Pick up BHA 10ft above the plug body

9.3.2. RIH to top pf plug body with 10ft/min while pumping 5bbls of D801 system at pumping rate of 0.8bpm

9.3.3. Proceed to bottoms up with 10bbls TIW

9.3.4. Upon completion bottom up, stop pumping and re-attempt to latch by repeating step 115 and 118 **(If necessary)**

10. If plug still unable to latch after multiple attempts, inform WSS and consult town to change BHA to cleanout run or VJB run – Contingency **(Subject to solid returned at surface during CT OPERATION– RUN#4 CLEANOUT RUN USING 1.81" VJB TO CLEAR REMAINING DEBRIS**

11. Apply CT Over pull to establish engagement of GS Pulling Tool (Approximately 2,000 to 3,000 lbs – surface) without firing the jars.

12. If plug is not free, RIH to set down weight to reset the jar and take over-pull (approximately 3,000lbs - surface) and fire the jars – noting time of detent delay mechanism. Repeat this step up to 5 times with increasing overpull. **Wellpro Tool Specialist to advise based on onsite parameters**

NOTE: If pumping has been performed, shut down pumps and allow pressure to stabilise and bleed before picking up

13. If plug is latched but unable to free, increase over-pull in 1,000 – 2,000 lbs increments (surface) - noting time of delay (i.e., shorter delay for larger over-pull), until the fish is free. Never exceed 80% of the yield of the CTU string or 80% of the maximum allowable over-pull on the B.H.A., whichever is the less

14. Once the tool string is released with the PXN plug (normal string weight is observed on weight gauge), proceed POOH to surface. It is not recommended to slack off weight back down on the plug body.

15. If the tool string remains unreleased, slack off weight to re-cock the jar and repeat an over pull indicated in the table below;

Weight Gauge Reading before over pull (lbf)	Over pull at surface (lbf)	Weight Gauge Reading after over pull (lbf)	Pipe movement (ft)	No. of Attempt
	3,000			
	5,000			
	6,000			
	7,000			
	8,000			
	9,000			
	10,000			

Fishing PXN Plug Table

16. In the event of CT stuck condition while retrieving the plug to surface (due to minimum restriction in tubing), apply an upward jarring action until maximum allowable CT overpull to free the stuck plug.

17. If plug is unable to free after maximum allowable CT overpull is applied, start pumping to circulation pressure required to activate GS pulling tool to release he stuck plug

18. Pick up BHA 30ft from initial stuck depth and stop pumping. RIH again slowly and soft tag to confirm on the latest PXN plug depth (Flag CT). Report the depth of PXN plug depth. Once tagged, start pump to release in case the GS was initially latched. POOH CT to surface.

19. Once CT is at surface, box up and release the plug from GS tool. If PXN plug is missing, consult town on way forward.

CT CONTINGENCY#1: MILLING OPERATION (DURING RUN#1 & 2)

1. In the event of BHA unable to pass through the HUD in run#1 or run#2 with jetting attempt, proceed to make up milling BHA as per **BHA#7 2.281" Junk Mill Bit** in **Appendix 1.**

2. Perform function test of the mill bit to determine pump rate and pressure parameter. Record the data in the table below, do not exceed **5,000psi.** Flow rate range for the motor to operate is **0.71 – 1.43bpm**. (Refer to the motor performance data)

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1		
1.1		
1.2		
1.3		

3. Repeat step 4 till 11 in Run#1 prior RIH
4. Start RIH BHA to the last HUD depth while pumping TIW at minimum rate permissible (0.3bpm).
   - 4.1. Refer to CT Tubing Force simulation (Orpheus modelling), refer Appendix III.
   - 4.2. 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.

   - 4.3. Maximum CT speed running in hole is 30-50 ft/min.
   - 4.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.
   - 4.5. Closely observe weight indicator in control cabin while running in hole.
   - 4.6. Observe return all the times.
   - 4.7. Regularly inform WSS on job status at all times.
   - 4.8. Do not exceed circulating pressure safety limits 5,000 psi.
   - 4.9. If the well condition differs from original job design, contact appropriate personnel in charge before proceeding.
   - 4.10. At all time, while RIH, the injector torque control shall be set at the minimum pressure required to move the CT string at specified speed.
5. Once BHA reach at 30 m above HUD, slow down the speed to 10ft/min and record the weight as per below

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

6. Once complete pull test, continue RIH slowly at 10 ft/min and tag the HUD without pumping (Do Not Slack off more than 500lbf – surface).
7. Once HUD is tagged, pick up BHA 10m above HUD and proceed to record off bottom parameter.
8. Start to pump TIW to activate the motor as per motor performance data. Record the pressure as no load pressure (P no load). Circulating pressure will increase exceeding Pno load during milling.

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1		
1.1		
1.2		
1.3		

9. Ensure that constant fluid returns at surface prior to start milling operation.
10. Once off bottom parameters have been recorded, increase pumping rate as per Milling Specialist recommendation and continue to RIH until loss weight (500lbf slack off) is observed on mill and start milling while maintaining -500 lbs weight on bit. (Refer to motor performance data for flowrate to activate motor).
    - 10.1. Do not exceed the maximum CT working pressure of **5,000 psi.**
    - 10.2. Flow rate range for the motor to operate is **0.71 – 1.43bpm**.
    - 10.3. Please record the bottom hole circulating pressure. **Keep the DP around 600 - 900 psi until BHA reach last held-up. Maximum DP is 1,180 psi (PLoad – P No Load).**
    - 10.4. If motor stall, stop pumping, bleed off pressure, and pick up BHA 20ft above the current depth. Resume the pumping and note the pressure and compare to the previous pressure. Refer to Motor Performance Curve below as guideline.

NOTE: Penetration rate should be limited to a rate that gives good cutting returns. If unable to see cutting returns, perform wiper trip back up to the initial penetration depth and introduce D801 gel / nitrified fluid where applicable to establish good returns at surface. DO NOT PROCEED ANY FURTHER WITHOUT RETURNS AT SURFACE

11. Once milling pattern is established, vary the set down weight between 500 to 1,000 lbf (surface) until achieve 800 – 1200 psi differential pressure
12. Once BHA is 5ft above PXN plug, stop pump and dry tag PXN plug at 2,860m/9,383ft MDDF, proceed to perform pumping 1x CT/Tubing Annulus volume with gel and follow up 2x Bottoms up with TIW till clear return observe on surface
13. After return is clear, proceed to POOH BHA to surface and secure the well.
14. Prepare BHA for CT next run.
15. CT Supervisor/Operator to update pipe tracking management file and string file fatigue after each run and share the file with town.

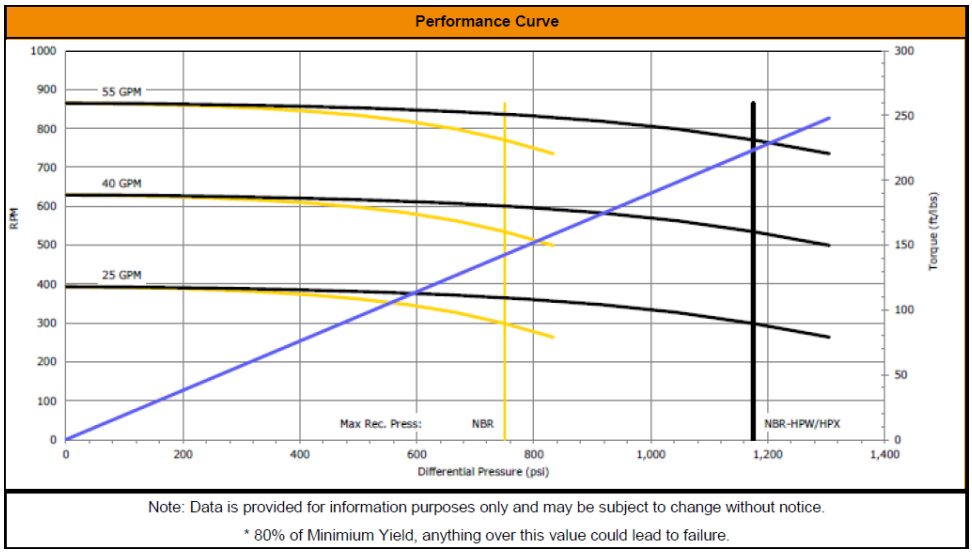


Figure 1: Generic Milling Guidelines, Motor Performance Graph

CT CONTINGENCY#2: CT SOLID CLEANOUT UNTIL TOP OF PXN PLUG OR VJB AT 2860M-MDDF

1. In the event that plug is unable to latch after multiple latch attempts**,** inform WSS and consult town for way forward either to proceed with cleanout run or VJB run to top of PXN Plug **(Subject to solid recovered on surface during Run#4 VJB).**
2. If town agree to:
   2.1. Proceed with cleanout, to perform CT solid cleanout run according to procedure in CT OPERATION – RUN#2 CT SOLID CLEANOUT UNTIL TOP OF PXN PLUG AT DEPTH 2,860M- MDDF
   2.2. Proceed with VJB, to perform debris cleanout using VJB according to procedure in CT OPERATION– RUN#4 CLEANOUT RUN USING 1.81" VJB TO CLEAR REMAINING DEBRIS

CT CONTINGENCY#3: 2.125" IMPACT HAMMER WITH 2.25" BLINDBOX TO HAMMER STUCK PLUG TO NO-GO

1. Make up **BHA#8: 2.125" Impact Hammer C/W 2.25" Ported Blind in Appendix I**
2. Testing Up Acting Hammer
   - 2.1. Install a pull test plate. Ensure free flow. Make sure the slinger (above impact hammer) is unloaded (neutral position).
   - 2.2. Start pumping with the idle rate. Record flow rate and circulating pressure.
   - 2.3. Slowly pick up BHA until pull test plate touched bottom of riser, and apply overpull (500 lbs or more, depends on Toolman recommendation) and let the tool impact until stable frequency of hammering is achieved (note in remark). Record flow rate and circulating pressure. Increase pump rate in stages and repeat function test.

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1.0		
1.1		
1.2		
1.3		

   - 2.4. Stop circulation & slowly unload the accelerator by lowering the pull test plate below the riser. Any trapped pressure shall release.
   - 2.5. Tool may start to impact before the pressure bleeds off to zero once the tool returned in the neutral position. Remove the pull test plate from the BHA.
3. Testing Down Acting Hammer
   - 3.1. Connect a ported bullnose to the bottom of the shifting tool to ensure free flow.
   - 3.2. Start pumping with the idle rate. Record flow rate and pressure.
   - 3.3. Slowly lower BHA until ported bullnose in contact with main deck. Then apply snubbing force (not more than 500 lbs) and let the tool impact until stable downward hammering frequency is achieved. Record flow rate and circulating pressure. Repeat the function test by increasing the pump rate in stages.

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1.0		
1.1		

1.2		
1.3		

3.4. Stop circulation & slowly unload the accelerator. Any trapped pressure shall release.

3.5. Tool may start to impact the pressure bleeds off to zero once the tool returned in the neutral position.

4. Proceed to perform function test of the Impact Hammer to determine pump rate & pressure parameter for the tools to activate. Record the data in the table below, do not exceed 5,000psi

Flowrate (bpm)	Pressure (psi)	Remarks
0.3		
0.5		
0.7		
0.9		
1		
1.1		
1.2		
1.3		

5. Repeat step 4 till 11 in Run#1 prior to RIH.

6. Start RIH BHA to the stuck plug depth while pumping TIW at minimum rate permissible.

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

6.2. 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.

6.3. Maximum CT speed running in hole is 30-50 ft/min.

6.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.

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

6.6. Observe return all the times.

6.7. Regularly inform WSS on job status at all times.

6.8. Do not exceed circulating pressure safety limits 5,000 psi.

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

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

7. Once BHA reach at 30 m above top of fish, slow down the speed to 10ft/min and record the weight as per below

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

8. Once complete pull test, continue RIH in dry condition and tag the top of fish without pumping (Do not slack off more than 1000lbf – surface). Compare with the CT Flag#
9. Tag top of fish twice and pick up BHA 10ft above the fish to neutral CT weight and start pumping at optimum rate.
10. RIH BHA slowly at 1ft/min once circulating pressure is stabilized and apply set down weight on PXN plug (1000 lbs) to activate the hammer.
11. Continue to hammer for a period of times and monitor depth changes with respect to CT Flag# to monitor progress made. If BHA is moving downwards, proceed to push down the PXN plug until the it has landed at No-Go depth (2860m MDDF).
12. If fish is unable to be pushed down to No-Go depth with maximum slack-off force applied, consult town for next action.
13. Once fish is hammered down to 2860m, POOH CT BHA to surface. Check condition of blind box at surface.

CT CONTINGENCY#4: HPT + GR-CCL RUN & DUMMY TUBING CUTTER RUN

1. Make up **BHA#9 Memory GR-CCL and 2.25" SMART Blaster as per Appendix I** Physically measure and record the length of the string. Record time taken from start rig up BHA until just before ready to RIH (in minutes)

Logging Interval (m-MDDF)
2760 – 2860m-MDDF

2. Repeat step 4 till 11 in Run#1 prior RIH
3. Open well and wait until it is stabilized. RIH GR/CCL to cut depth 2858.5 m-MDBDF (Cutter Shot Depth) with speed 30 ft/min. Slow down at completion accessories.

NOTE: Do not exceed 500 lbs (surface) set down weight.

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

3.2. 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.

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

3.4. Observe return all the times.

3.5. Regularly inform WSS on job status at all times.

3.6. Do not exceed circulating pressure safety limits 5,000psi

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

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

4. RIH BHA 2798.5 m, perform weight check Wait for 5 minutes to obtain average pressure and temperature data. This data will be used to establish lower limits for Pressure and Temperature parameters.

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

5. Continue RIH to tubing cut depth at 2858.5 m MDDF. Once reach at tubing cut depth at 2858.5m- MDDF, repeat weight check and pressure & temperature recording from step above.

Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

6. Then RIH to tag top of PXN plug at 2860 m MDDF. Do not exceed 1000 lbs (surface) set down weight Stop for 5 minutes, record pressure & temperature.
7. Once completed, continue with GRCCL sequence as per Figure 2
8. Log up at 10m/min as per Geowell logging program. Stop at 2760 m-MDDF (top logging interval) for 5 minutes for tool to gather parameters. Then continue to log down to 2860 m MDDF.

   NOTE: Please consult with CTU supervisor to pump at 0.5 bpm while doing correlation to straighten CT string as much as possible to eliminate buckling issue.
9. Once complete 1st pass. Stop pumping and wait for 5 minutes.
10. Repeat step 10 and 11. Log up at 15m/min to 2760m MDDF (top logging interval).
11. Once completed, RIH BHA back 2860 m-MDDF. Once CT tag PXN plug (Do not exceed 1000 lbs (surface) set down weight and put CT in tension. (Flag the CT). Mark CT as Flag#3

Flag Number	Colour
Flag #3	

12. Flagging must be done while CT is in tension. Do not flag CT when BHA sits at bottom of the well. Flagging the CT must remain consistent at the front of CT wheel throughout the operation. Do not continually adjust running speed trying to match the specified logging speed after starting. A constant speed is far more important and DO NOT let the flag pass into the injector head.
13. Pull up 1.5m above from the Flag #3 to get the string in tension and stop at 2858.5 m-MDDF as flag for Tubing Cut – Flag CT with Flag #4

Flag Number	Colour
Flag #4	

14. Perform CCL pass#2 and POOH to surface at 30 ft/min.
15. Once at surface, download data and send to town for verification. If data is good, proceed with depth offset verification.

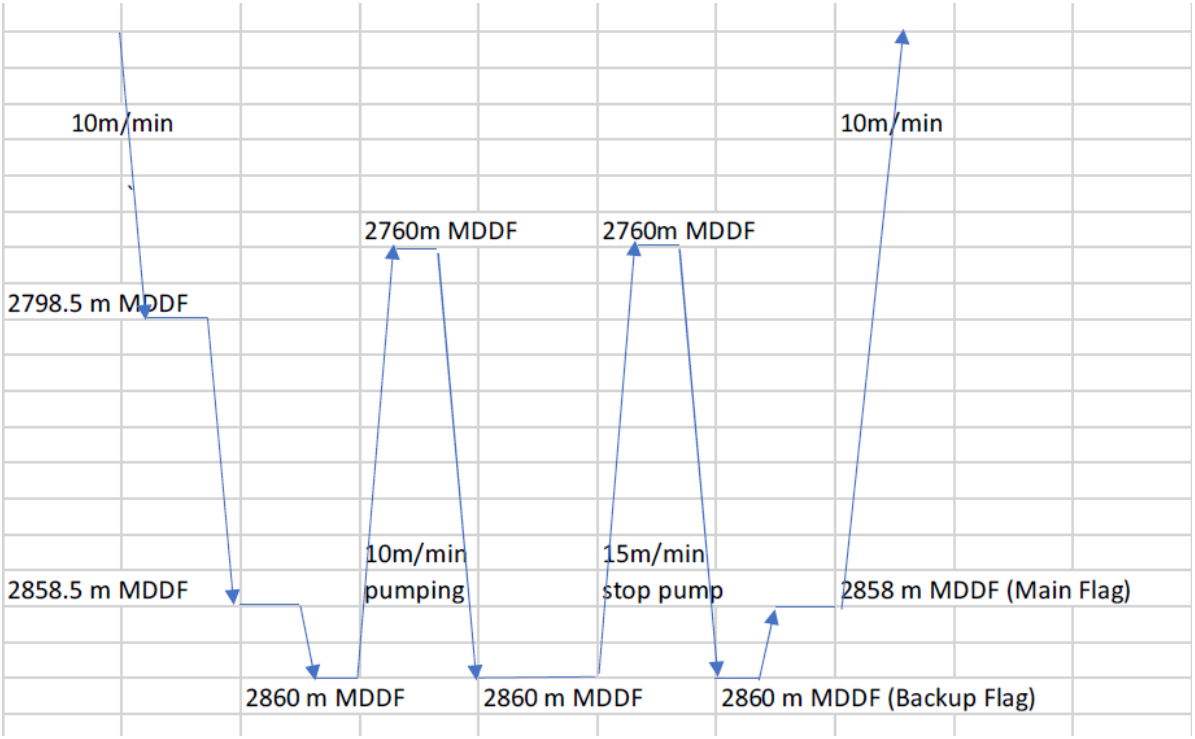


Figure 2: Actual SMART Blaster + GRCCL Running Sequence

16. If data downloaded is abnormal, please consult with supervisor onboard and town for next instructions
17. Lay down GR/CCL string tool. Download memory data to construct GR/CCL log per raw data without depth shifted.
18. Compare GR/CCL log with the reference log and determine the "offset" before both logs correspond.

CT CONTINGENCY#5: TUBING CUTTER USING SMART BLASTER

1. Engineer to program SMART Blaster based on the below parameters (show table of temperature, pressure, and activation time range). WSS must verify that the correct parameters have been programmed to the SMART Blaster prior to make up tool.

Temperature	Pressure	Activation Time Range

2. Make up **BHA#10 Smart Blaster and Tubing Cutter as per Appendix I**. Measure the distance from top of GSI's crossover until bottom of tubing cut tool. Record the length in the table below to determine offset from previous run BHA length

Distance	Length (ft)
Top of GSI's Crossover to Bottom Tubing Cutter (A)	

3. Repeat step 4 till 11 in Run#1 prior RIH
4. Start RIH BHA to last flag depth while pumping at 0.5bpm and 30 ft/min

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

   4.2. 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.

   4.3. CT Maximum CT speed running in hole is 30ft/min.

   4.4. Slow down CT speed to 10 ft/min, 50 ft before and after passing through completion accessories.

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

   4.6. Observe return all the times.

   4.7. Regularly inform WSS on job status at all times.

   4.8. Do not exceed circulating pressure safety limits 5,000 psi.

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

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

5. Once BHA reach at 10 m above flag#4 (2848.5m MDDF), slow down the speed to 10ft/min and record the weight as per below

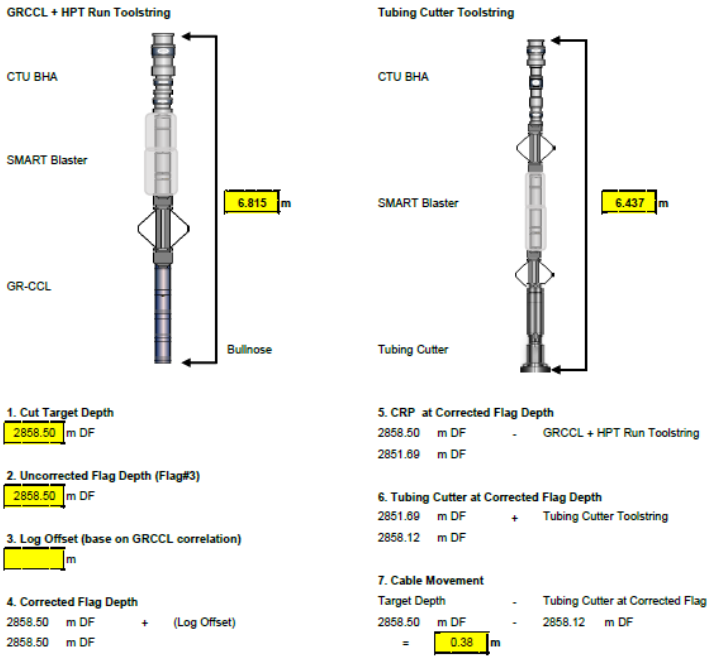
Depth (ft)	RIH Weight (lbf)	Static Weight (lbf)	Pick Up Weight (lbf)

6. Continue to RIH and stop when the flag is located at the front of CT wheel. Carefully tie in with the mark at the front of counter previously marked.

   NOTE: Do not exceed 500 lbs (surface) set down weight.

   NOTE: Do not remove or shift the CT flag as it will be used as a reference mark for the consequent runs.

7. RIH BHA at idle pump rate 0.5bpm until max 1m past Flag#4. If encounter set down, immediately stop CT movement as it may damage the explosive tubing cutter.
8. Referring to the program, calculate the CT movement from difference between intended cutter shot depth, 2858.5 m-MDDF and the current cutter shot depth as refer the calculation sheet as below:



(From calculation in no.7, If positive, RIH CT by offset depth. If negative, POOH CT by offset depth)

9. Position BHA to the correct firing depth based on final offset with respect to Flag#4 with CT in tension, following mechanical depth counter as final reference. Once at correct firing depth, flag CT with Flag#5. Record wellhead pressure, CT tubing pressure and static weight.

Flag Number	Colour
Flag #5	

THP (psi)	CTP (psi)	CT Static Weight (lbf)

10. Wait for the SMART Blaster to fire the Tubing Cutter. Monitor elapsed time and changes in THP as firing indicators.
11. Wait for 15 minutes after fired. Then, RIH BHA maximum 1m past Flag#3 (PXN plug @ 2860m) to confirm whether tubing is fully cut. If encounter held up, do not exceed 500 lbs (surface) set down weight.
12. POOH BHA to surface.
13. On surface, laydown tool string and physically check on tool string. Visually verify that all charges fired. Report to town immediately if charges were partially or misfired. Consult town for way forward if encountered held up after tubing cutter fired (potential partial tubing cut).

NOTE: In the event of no firing indication, wait for 15 minutes after firing time. The tool will close the Firing Window which stops comparing downhole pressure and temperature against the values. Firing cannot occur after this time. After the Firing Window closes the tool is in SAFE MODE. The tool string are then safe to be POOH.

MISFIRE PROCEDURE SMART BLASTER

1. In the event of a misfire, recover the SMART Blaster to surface out of the pressure and temperature parameter set on the SMART Blaster and ensuring that all normal explosives safety handling procedures are adopted. Remove the explosive firing head from the SMART Blaster and make safe.

   NOTE: Ensure that non-essential personnel are cleared from the area. Only Specialist trained in handling an explosive is to handle the misfired BHA.

2. Engineer is to check the tool for potential/reasons for the problem. Engineer and Client representatives in town will need to be advised first before proceeding with the troubleshooting of the tool.
3. If the SMART Blaster has failed to initiate, redress complete tool string and re-run subject to town agreement.
4. Once fault has been fully rectified, test firing simulation on surface to ensure that >200V can be delivered to the detonator/igniter and re-run tool string.
5. Ensure that all explosives are stored back in the approved area.

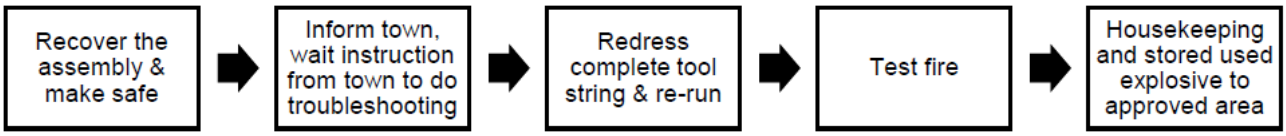


Figure 5: SMART Blaster Misfire Flowchart

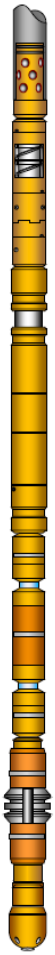
APPENDIX I – BOTTOM HOLE ASSEMBLY SCHEMATIC

BHA #1: 1-11/16" BI-DIRECTIONAL SHIFTING TOOL

DIMENSION BID

BHA DIAGRAM #1- 2.125" BI-DIRECTIONAL SHIFTING TOOLS

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.31"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Run#1	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.84	0.8
	1-11/16" MHA Disconnect drop ball 1/2"	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.4	3.2
	Impact Hammer Accelerator	1.0" AMMT Box	1.0" AMMT Pin		1.690	6.3	9.57
	Impact Hammer	1.0" AMMT Box	1.0" AMMT Pin		1.690	3.90	13.47
	X-Over Sub	1.0" AMMT Box	1.5" AMMT Pin		2.125	0.35	13.82
	Bi-directional Shifting Tools	1.5" AMMT Box	1.5" AMMT Pin		2.125	1.87	15.69
	Jetting Nozzle	1.5" AMMT Box			2.125	0.50	16.19

BHA LENGTH	16.19
MAXIMUM OD	2.125"
MINIMUM ID	0.563"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

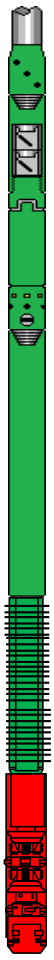
Open

BHA #2: 1.69" SPINCAT NOZZLE C/W 1.69" DOWNHOLE FILTER

DIMENSION BID

BHA DIAGRAM #2- 1.69" SPINCAT NOZZLE C/W 1.69" DOWNHOLE FILTER

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.31"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Run#2	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.30	0.3
	1-11/16" MHA Disconnect drop ball 5/8" Shear pressure 5,456 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5,000 psi	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.30	2.6
	5 ft Straight Bar	1.0" AMMT Box	1.0" AMMT Pin		1.690	5.0	7.60
	Downhole Filter	1.0" AMMT Box	1.0" AMMT Pin		1.690	3.2	10.80
	SpinCat	1.0" AMMT Box			1.690	1.00	11.80

BHA LENGTH	11.80
MAXIMUM OD	2.29"
MINIMUM ID	1.69"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

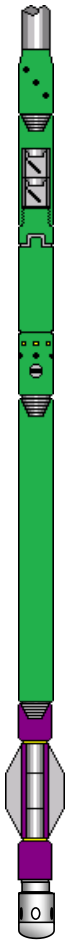
Open

BHA #3: 1.69" MULTIJET NOZZLE C/W 2.29" FLUTED CENTRALIZER

DIMENSION BID

BHA DIAGRAM #3- 1.69" MULTIJET NOZZLE C/W 2.29" FLUTED CENTRALIZER

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.31"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Run#3	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.30	0.3
	1-11/16" MHA Disconnect drop ball 5/8" Shear pressure 5,456 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5,000 psi	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.30	2.6
	5 ft Straight Bar	1.0" AMMT Box	1.0" AMMT Pin		1.690	5.0	7.60
	Fluted Centralizer	1.0" AMMT Box	1.0" AMMT Pin		2.290	1.0	8.60
	MultiJet Nozzle	1.0" AMMT Box			1.690	1.00	9.60

BHA LENGTH	9.60
MAXIMUM OD	2.29"
MINIMUM ID	1.69"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

Open

BHA #4: 1.81" VENTURI JUNK BASKET

DIMENSION BID

BHA DIAGRAM #4- 1.81" VENTURI JUNK BASKET

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.31"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Run#4	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	External Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.41	0.4
	1-11/16" MHA Circulating drop ball 1/2" Disconnect drop ball 7/16" Burst Disc 5-7,000 psi	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.3	2.7
	Crossover Sub	1.0" AMMT Box	1.0" AMMT Pin		1.690	0.5	3.19
	Venturi Junk Basket	1.0" AMMT Box	1.0" CSWP Pin		1.810	2.67	5.86
	Venturi Junk Basket Extension Debris Chamber	1.0" CSWP Box	1.0" CSWP Pin		1.810	3.00	8.86
	Profiled Shoe cw Flutter Cage	1.0" CSWP Box			1.810	0.58	9.44

BHA LENGTH	9.44
MAXIMUM OD	1.810"
MINIMUM ID	0.563"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

Open

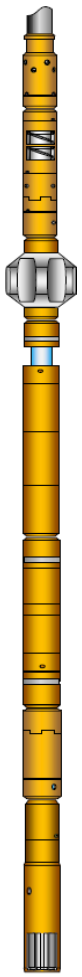
BHA #5: 1.765" FLOW RELEASE JDC C/W 2.125" STABILIZER

DIMENSION BID

BHA DIAGRAM #5- 1.765" FLOW RELEASE JDC C/W 2.125" STABILIZER

Client	Petronas Carigali
Field	Dulang B
Job Type	Fishing & Zone Change
Job No.	CT Run#5

Well	B-16ST3
Min Restriction	2.31"
BHP	
BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.688	0.60	0.6
	1-11/16" MHA Disconnect drop ball 1/2" Circulation 7/16", BD = Blank	1.0" AMMT Box	1.0" AMMT Pin		1.688	2.4	3.0
	NRT Stabilizer **(Optional)**	1.0" AMMT Box	1.0" AMMT Pin		2.125	5.6	8.58
	Dual Acting Hydraulic Accelerator	1.0" AMMT Box	1.0" AMMT Pin		1.688	5.6	14.17
	Dual Acting Hydraulic Jar	1.0" AMMT Box	1.0" AMMT Pin		1.688	5.51	19.68
	Lower Hydraulic Disconnect Disconnect drop ball 3/8", 5000psi	1.0" AMMT Box	1.0" AMMT Pin		1.688	1.6	21.28
	2" Non Slim Flow Release JDC for 1.376 EFN	1.0" AMMT Box			1.765	1.39	22.67

BHA LENGTH	22.67
MAXIMUM OD	2.125"
MINIMUM ID	1.69"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

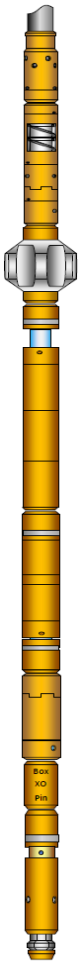
Open

BHA #6: 2.22" GS PULLING TOOL C/W 2.125" STABILIZER

DIMENSION BID

BHA DIAGRAM #6 2.25" GS PULLING TOOL C/W 2.125" STABILIZER

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.25"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Run#6	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.688	0.60	0.60
	1-11/16" MHA Disconnect drop ball 1/2" Circulation 7/16", BD = Blank	1.0" AMMT Box	1.0" AMMT Pin		1.688	2.4	3.0
	NRT Stabilizer **(Optional)**	1.0" AMMT Box	1.0" AMMT Pin		2.125	5.6	8.58
	Dual Acting Hydraulic Accelerator	1.0" AMMT Box	1.0" AMMT Pin		1.688	5.6	14.17
	Dual Acting Hydraulic Jar	1.0" AMMT Box	1.0" AMMT Pin		1.688	5.51	19.68
	Lower Hydraulic Disconnect Disconnect drop ball 3/8", 5000psi	1.0" AMMT Box	1.0" AMMT Pin		1.688	1.6	21.28
	Crossover	1.0" AMMT Box	1.5" AMMT Pin		2.125	0.42	21.70
	2-1/2" Nom GS Retrieval Tool for 1.81 ID FN	1.0" AMMT Box			2.220	1.29	22.57

BHA LENGTH	22.57
MAXIMUM OD	2.22"
MINIMUM ID	1.69"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

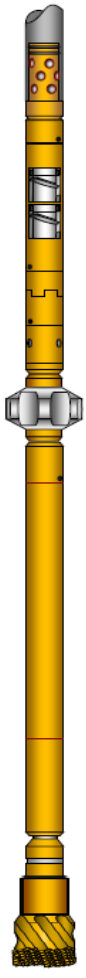
Open

BHA #7: 2.0" FLAT BOTTOM MILL 1.69" PDM MOTOR

DIMENSION BID

BHA DIAGRAM #1- 2.0" FLAT BOTTOM MILL 1.69" PDM MOTOR

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.25"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Contingency Run#1	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.41	0.4
	1-11/16" MHA Circulating drop ball 1/2" Disconnect drop ball 7/16" Burst Disc 5-7,000 psi	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.30	2.7
	NRT Stabilizer cw Sleeve	1.0" AMMT Box	1.0" AMMT Pin		2.125	2.7	5.39
	PDM- Mud Motor	1.0" AMMT Box	1.0" AMMT Box		1.690	8.6	13.99
	Mill, Spiral Blade Flat Bottom	1.0" AMMT Pin			2.000	0.84	14.83

BHA LENGTH	14.83
MAXIMUM OD	2.281"
MINIMUM ID	1.69"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

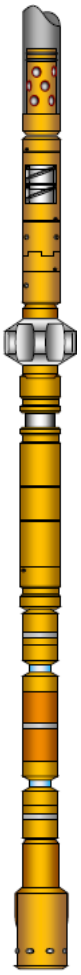
Open

BHA #8: 1-11/16" IMPACT HAMMER c/w 2.25" PORTED BLIND

DIMENSION BID

BHA DIAGRAM #8- 2.125" IMPACT HAMMER c/w 2.25" PORTED BLIND

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.31"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Contingency Run#2	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.41	0.4
	1-11/16" MHA Circulating drop ball 1/2" Disconnect drop ball 7/16" Burst Disc 7,000 psi	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.3	2.7
	NRT Stabilizer	1.0" AMMT Box			2.125	2.7	5.39
	Dual Acting Impact Accelerator	1.0" AMMT Box	1.0" AMMT Pin		1.690	6.4	11.75
	Dual Acting Impact Hammer	1.0" AMMT Box	1.0" AMMT Pin		1.690	3.90	15.65
	Ported Blindbox	1.0" AMMT Box	Ported		2.250	0.85	16.50

BHA LENGTH	16.50
MAXIMUM OD	2.250"
MINIMUM ID	0.563"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

Open

BHA #9: 1.687" GRCCL C/W 2.25" SMART BLASTER

DIMENSION BID

BHA DIAGRAM #9- 1.687" GRCCL C/W 2.25" SMART BLASTER

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.31"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Contingency Run#3	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.30	0.3
	1-11/16" MHA Disconnect drop ball 5/8" Shear pressure 5,456 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5,000 psi	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.30	2.6
	Crossover	1.0" AMMT Box	15/16" SR		1.690	0.5	3.10
	Knuckle Joint	15/16" SR	15/16" SR		1.250	0.89	3.99
	Knuckle Joint				1.250	0.89	4.88
	SMART Blaster with UBC	15/16" SR	1-3/16 Go Pin		2.25	7.87	12.75
	Bow Spring Centralizer	1-3/16" Go Box	1-3/16 Go Pin		1.687	2.9	15.64
	Crossover	1-3/16" Go Box	15/16" SR		1.687	0.39	16.03
	GR-CCL	15/16" SR			1.687	6.33	22.36

BHA LENGTH	22.36
MAXIMUM OD	2.25"
MINIMUM ID	1.69"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

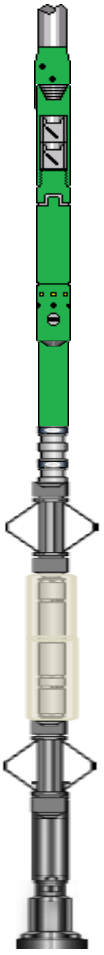
Open

BHA #10: 1.69" TUBING CUTTER C/W 2.25" SMART BLASTER

DIMENSION BID

BHA DIAGRAM #10- 1.69" TUBING CUTTER C/W 2.25" SMART BLASTER

Client	Petronas Carigali	Well	B-16ST3
Field	Dulang B	Min Restriction	2.31"
Job Type	Fishing & Zone Change	BHP	
Job No.	CT Contingency Run#4	BHT	

BHA DRAWING	DESCRIPTION	CONNECTION		ID	OD	TOOL LENGTH	CUMULATIVE LENGTH
		UPHOLE	DOWNHOLE	INCH	INCH	FT	FT
	Internal Dimple CT Connector	1.5" CT	1.0" AMMT Pin		1.690	0.30	0.3
	1-11/16" MHA Disconnect drop ball 5/8" Shear pressure 5,456 psi Circulating drop ball 5/8" Shear pressure 2,520 psi Burst Disc 5,000 psi	1.0" AMMT Box	1.0" AMMT Pin		1.690	2.30	2.6
	Crossover	1.0" AMMT Box	15/16" SR		1.690	0.5	3.10
	Knuckle Joint	15/16" SR	15/16" SR		1.250	0.89	3.99
	Knuckle Joint				1.250	0.89	4.88
	Bow Spring Centralizer	15/16" SR	15/16" SR		1.687	3.5	8.39
	SMART Blaster with UBC	15/16" SR	1-3/16 Go Pin		2.25	7.87	16.26
	Bow Spring Centralizer	1-3/16" Go Box	1-3/16 Go Pin		1.687	2.9	19.15
	Firing Head Adapter				1.687	0.23	19.38
	Shock Mandrel	1-3/16" Go Box	1-3/16 Go Pin		1.687	1.15	20.53
	2.063" Tubing Cutter	1-3/16" Go Box			1.690	0.59	21.12

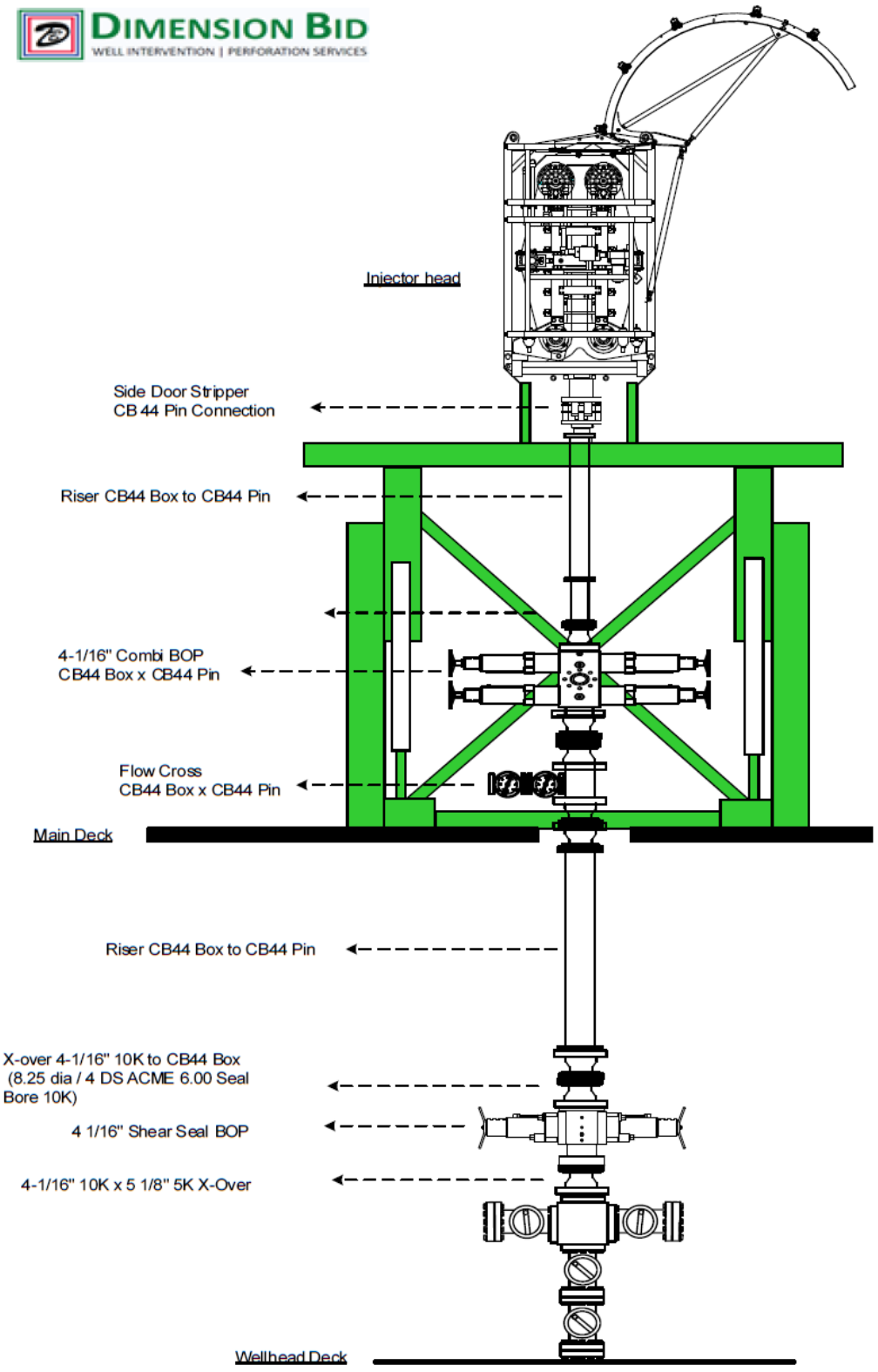
BHA LENGTH	21.12
MAXIMUM OD	2.25"
MINIMUM ID	1.69"

Prepared by:	Atikah Nazifah Mustafa
Review by:	
Revision:	
Date:	

ADDITIONAL INFORMATION:

Open

APPENDIX II – COILED TUBING STACK UP

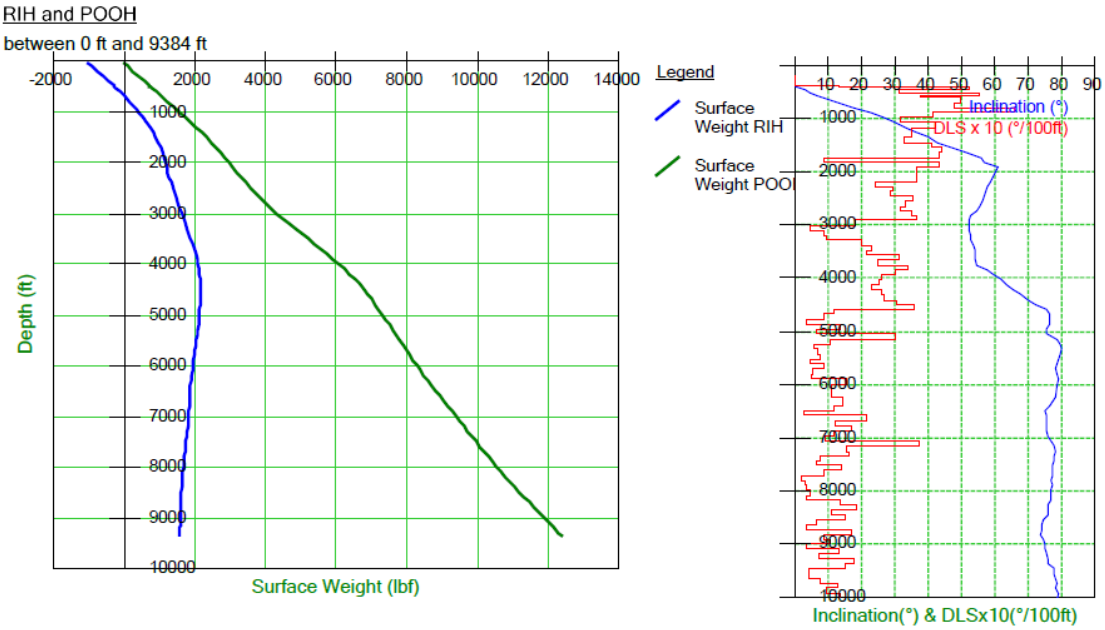


Open

APPENDIX III – ORPHEUS SIMULATIONS

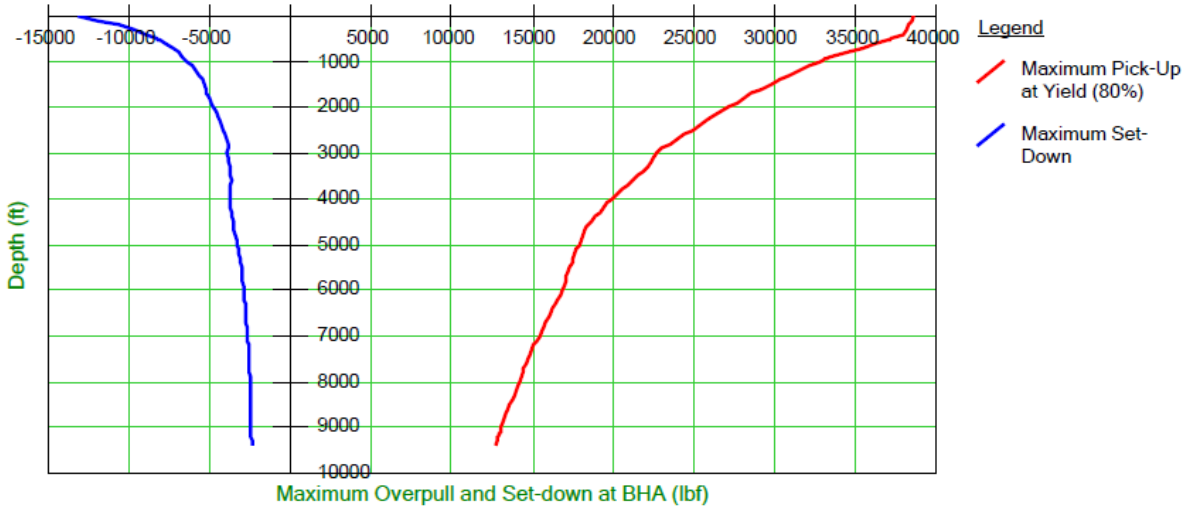
TUBING FORCE ANALYSIS AT FISH DEPTH

1. RIH AND POOH WEIGHT



2. MAXIMUM PICK-UP WEIGHT

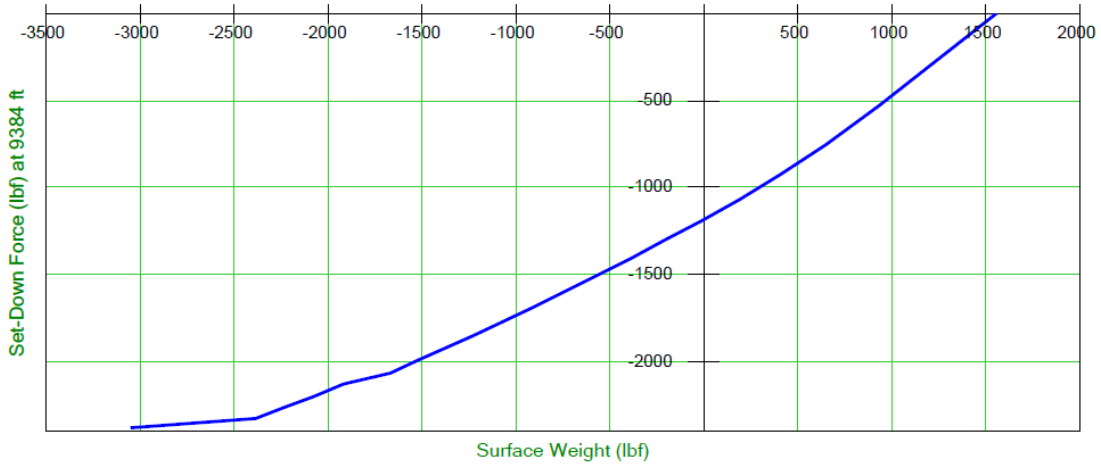
MD1 The available pick-up at 9384 ft based on 80% of yield strength is 12686 lbf.
The weight indicator reading will then be 38563 lbf.



Open

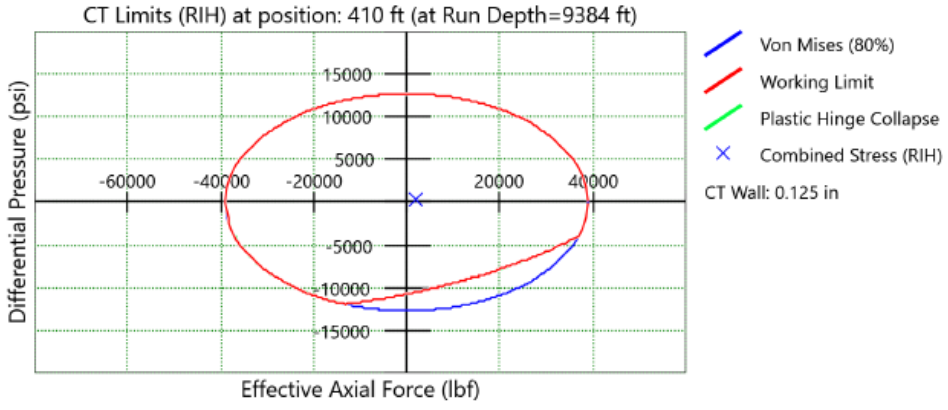
3. MAXIMUM STRING SET DOWN LIMIT

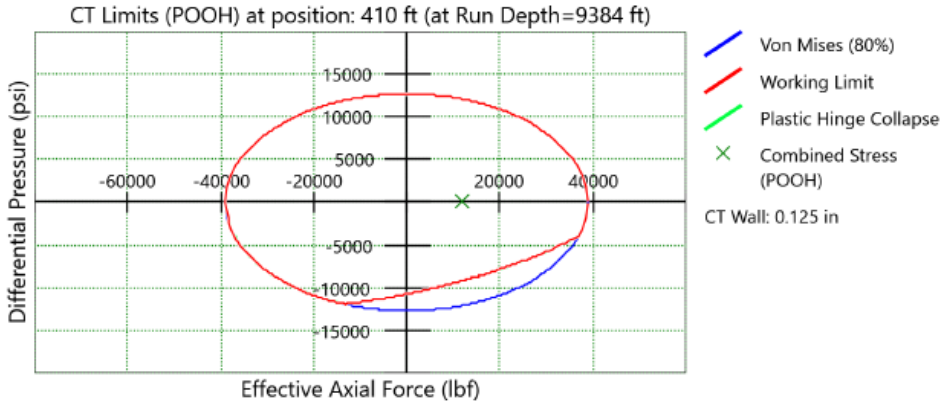
MD3 The available set-down force at 9384 ft is -2386 lbf at the end of the string.
The weight indicator reading will be -5323 lbf on surface.



MD4 CT stretch during steady RIH at 9384 ft is 2.71 ft.
CT stretch during steady POOH at 9384 ft is 6.58 ft.

4. STRING LIMIT

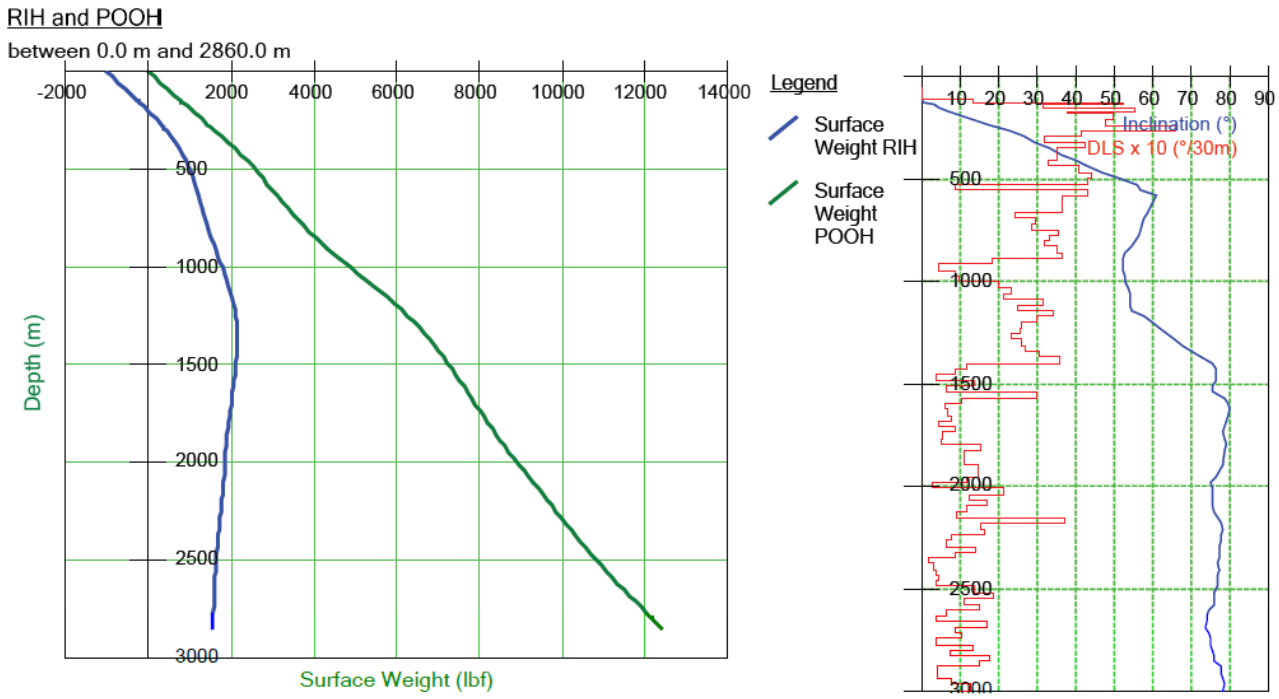




Open

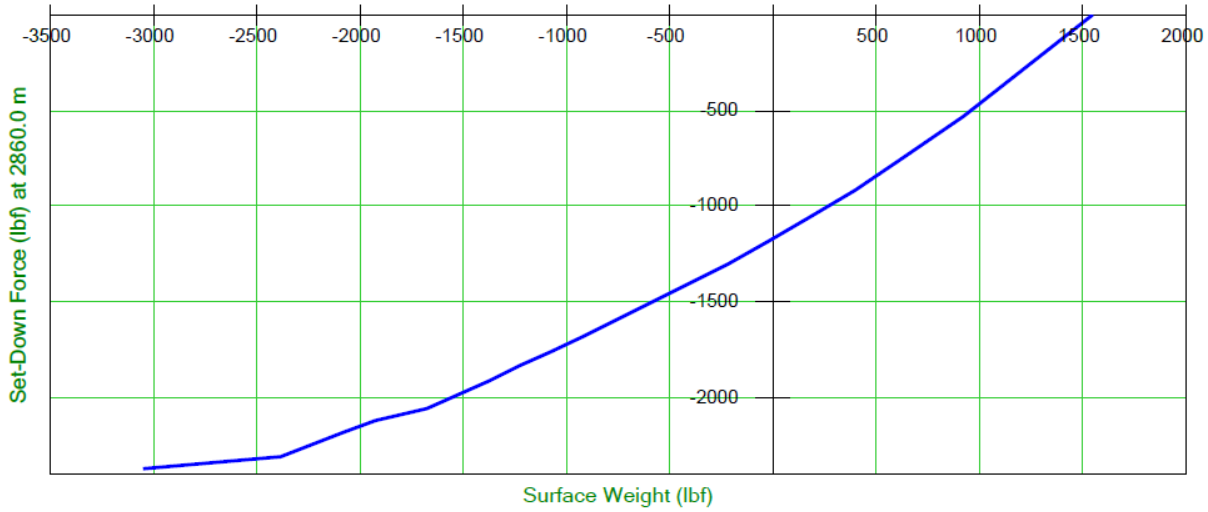
TUBING FORCE ANALYSIS (2.29' OD)

1. RIH & POOH WEIGHT



2. MAXIMUM STRING SET DOWN LIMIT

MD3 ☑ The available set-down force at 2860.0 m is -2372 lbf at the end of the string.
The weight indicator reading will be -5314 lbf on surface.

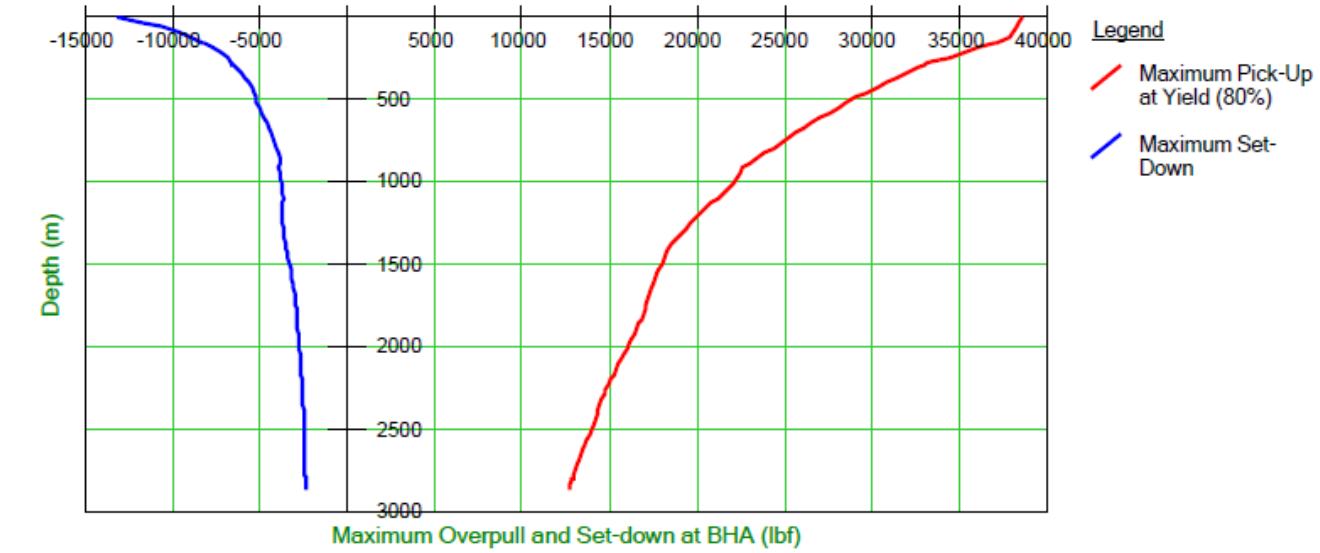


MD4 ☐ CT stretch during steady RIH at 2860.0 m is 0.82 m.
☐ CT stretch during steady POOH at 2860.0 m is 2.01 m.

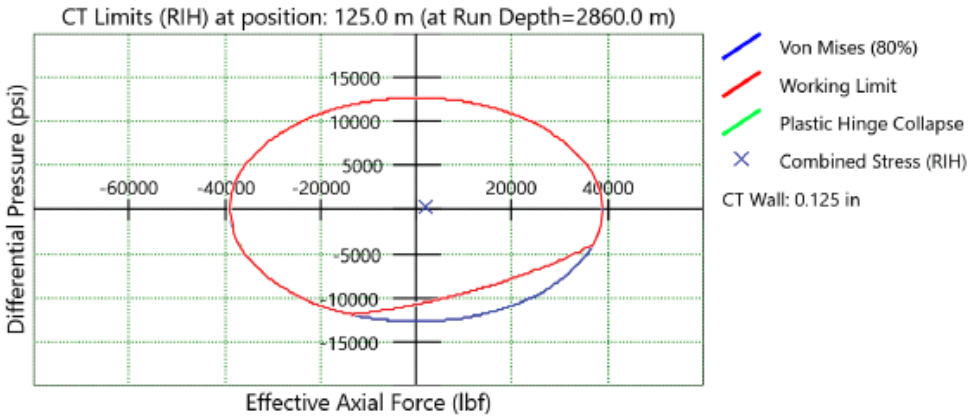
Open

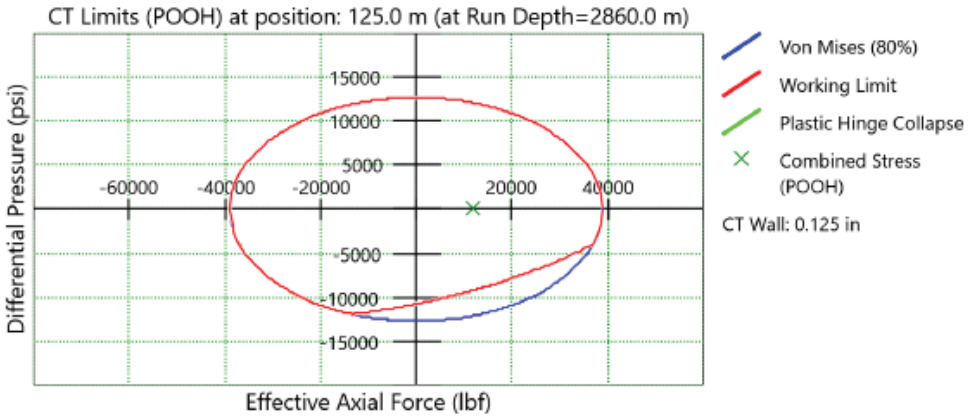
3. MAXIMUM STRING PICK UP LIMIT

MD1 The available pick-up at 2860.0 m based on 80% of yield strength is 12661 lbf.
The weight indicator reading will then be 38559 lbf.



4. STRING LIMIT

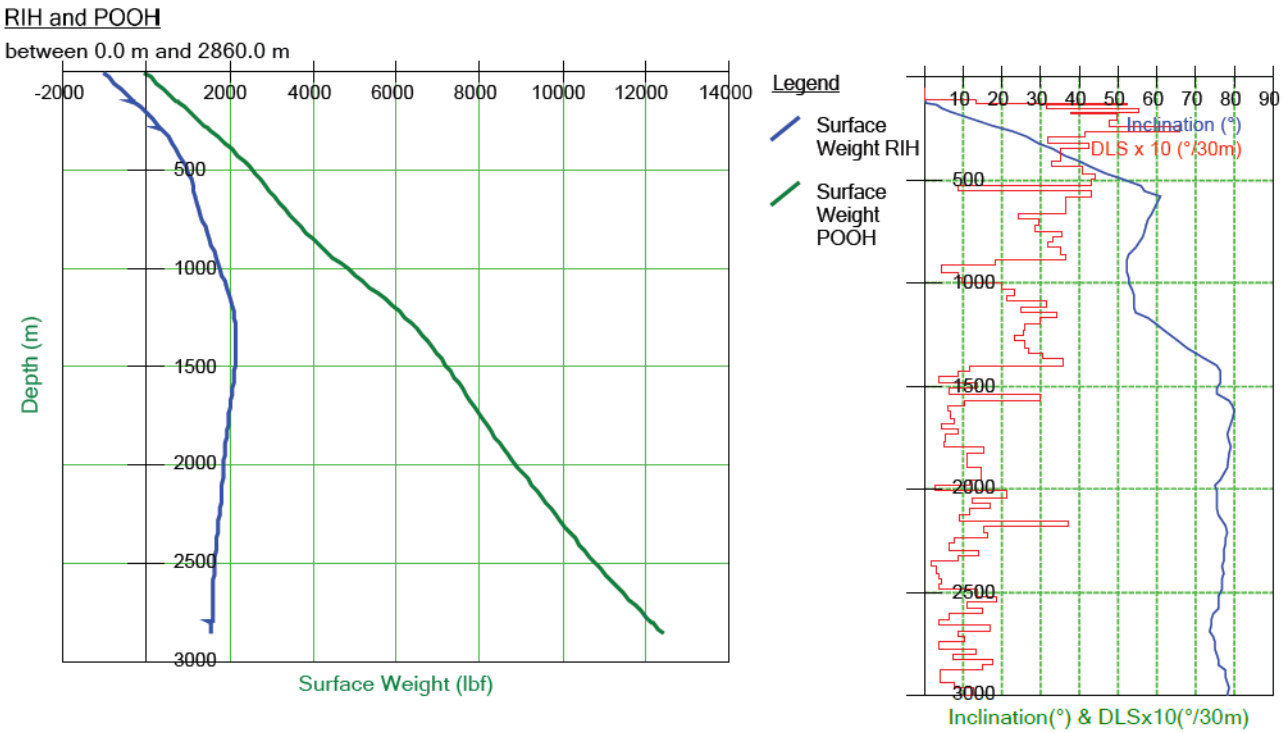




Open

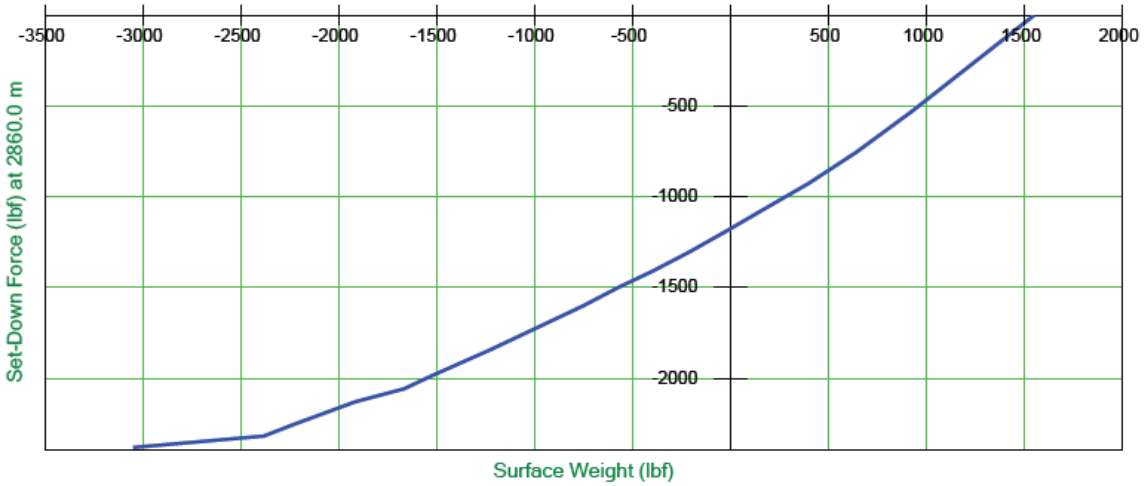
TUBING FORCE ANALYSIS (2.25" OD)

1. RIH & POOH WEIGHT



2. MAXIMUM STRING SET DOWN LIMIT

MD3 ■ The available set-down force at 2860.0 m is -2380 lbf at the end of the string.
The weight indicator reading will be -5318 lbf on surface.
The minimum available set-down force is -2319 lbf at 2795.3 m.

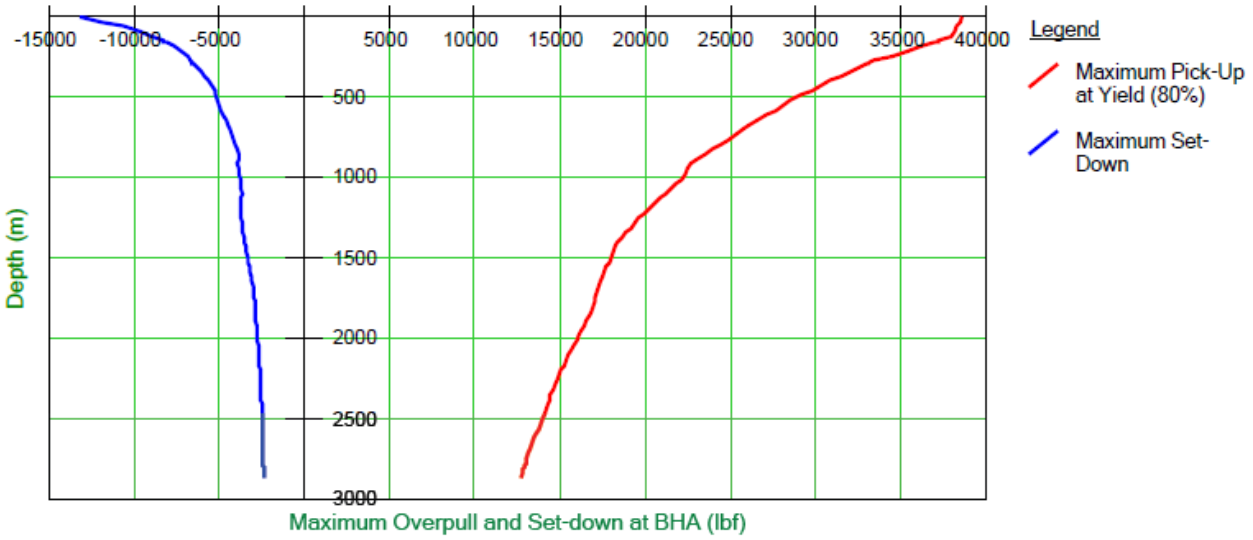


MD4 ☐ CT stretch during steady RIH at 2860.0 m is 0.82 m.
☐ CT stretch during steady POOH at 2860.0 m is 2.01 m.

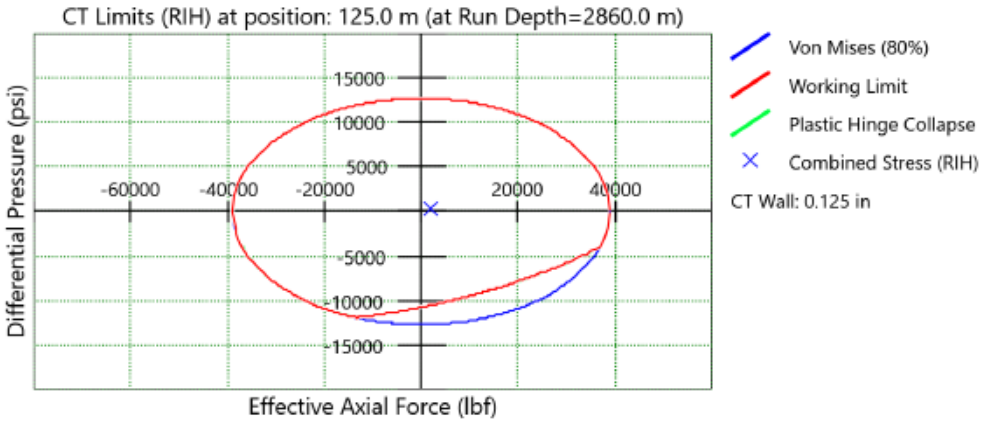
Open

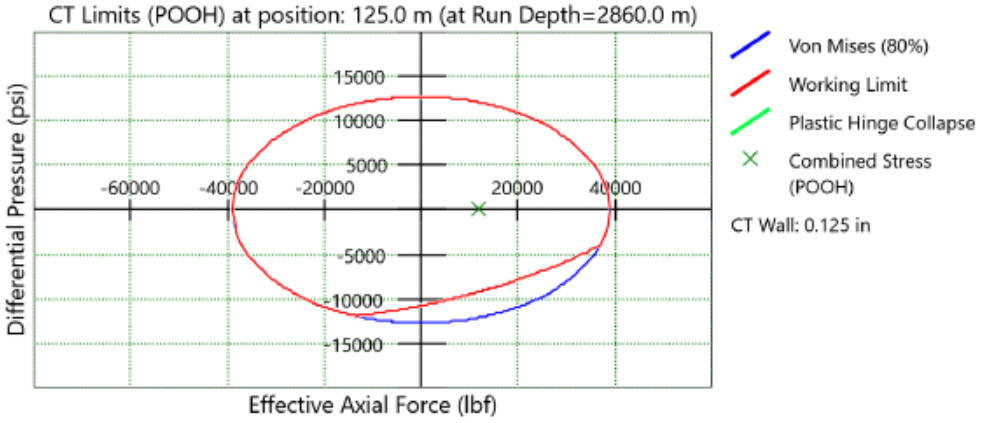
3. MAXIMUM STRING PICK UP LIMIT

MD1 The available pick-up at 2860.0 m based on 80% of yield strength is 12681 lbf.
The weight indicator reading will then be 38555 lbf.



4. STRING LIMIT



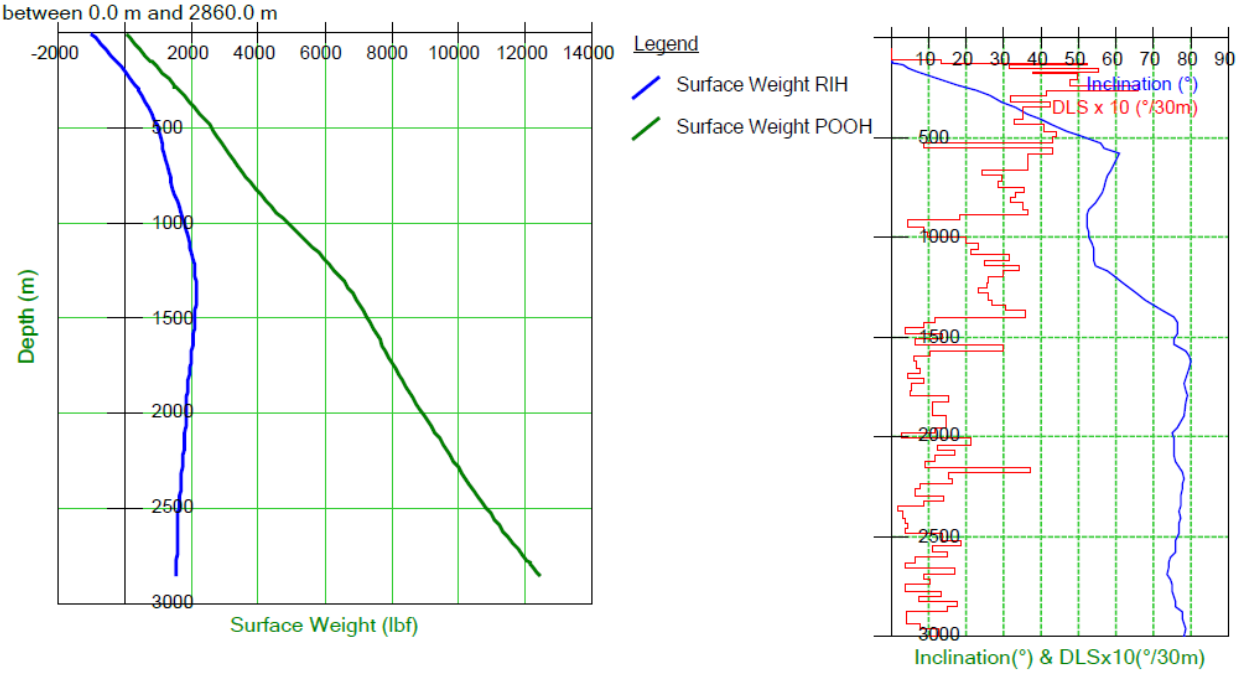


Open

TUBING FORCE ANALYSIS (TUBING CUTTER)

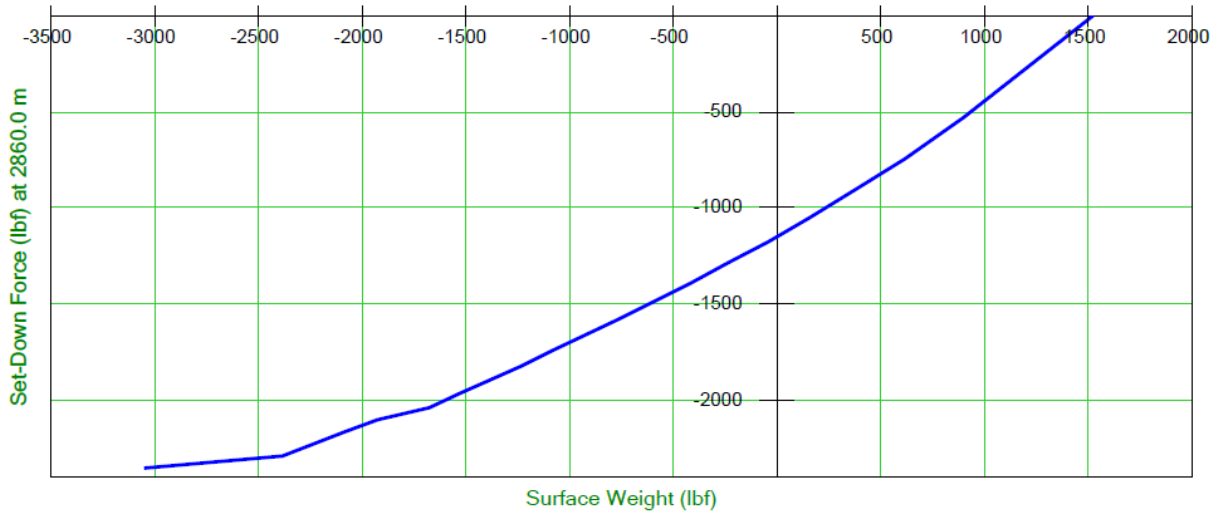
1. RIH & POOH WEIGHT

RIH and POOH
between 0.0 m and 2860.0 m



2. MAXIMUM STRING SET DOWN LIMIT

MD3 ■ The available set-down force at 2860.0 m is -2352 lbf at the end of the string.
The weight indicator reading will be -5298 lbf on surface.

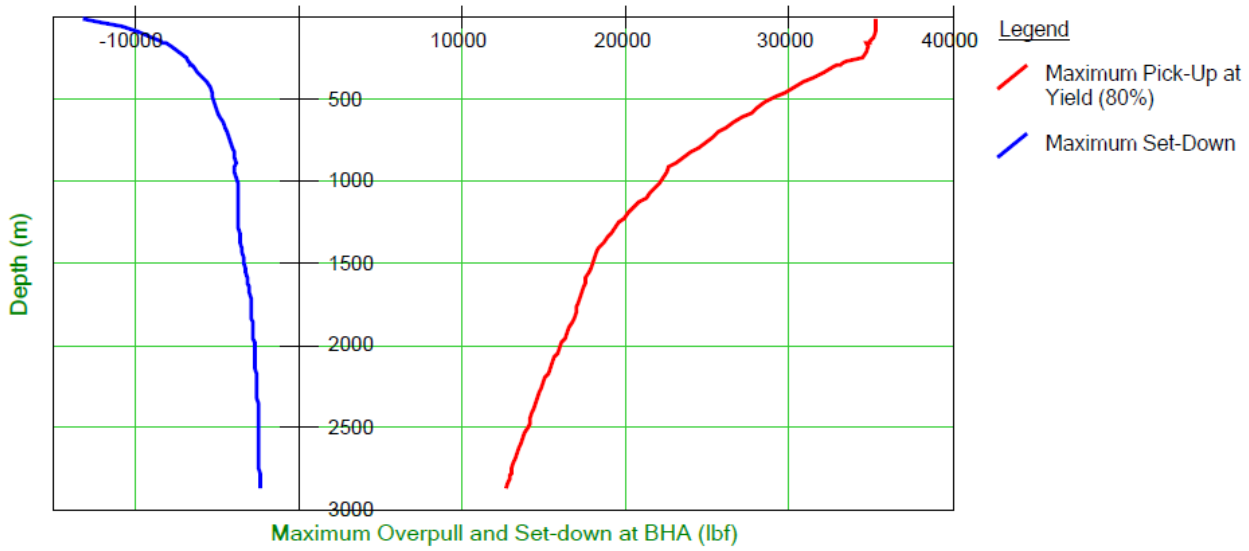


MD4 ☐ CT stretch during steady RIH at 2860.0 m is 0.82 m.
☐ CT stretch during steady POOH at 2860.0 m is 2.01 m.

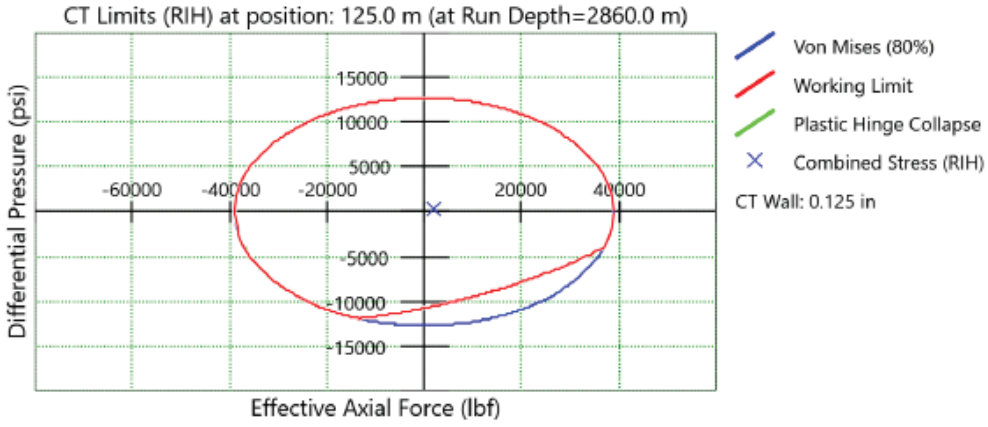
Open

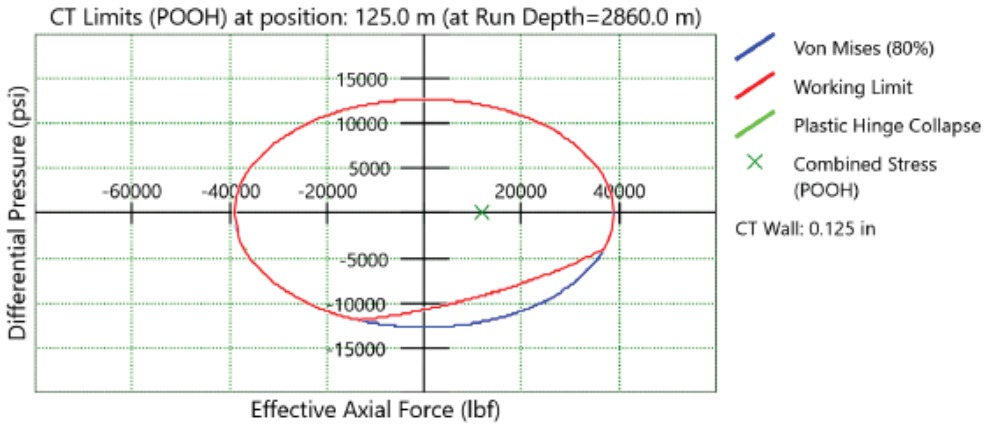
3. MAXIMUM STRING PICK UP LIMIT

MD1 The available pick-up at 2860.0 m based on 80% of yield strength is 12659 lbf.
The weight indicator reading will then be 38560 lbf.



4. STRING LIMIT





Open

APPENDIX IV – CIRCA SIMULATION

Project: Clean-out until top of plug Field-Well: Dulang - B16

Flow Summary

SUMMARY OF FLOW RESULTS

Produced Fluids	
Pressure known at:	Perforations
Production Mode:	No Production
Fluid Composition:	Oil Only
Circulated Fluids	
Fluid Composition:	Nitrified Water
Liquid:	0.80 bbl/min
Solids:	0.00 bbl/min
Gas:	300.0 scf/min
Circulation Point:	2860.00 m
HHP Required :	55.32 HP
COMPLETION:	
Wellhead Pressure.....	499.5 psi g
Hydrostatic pressure loss.....	891.3 psi
Friction pressure loss.....	510.6 psi
Kinetic pressure loss.....	-3.7 psi
Restriction pressure loss.....	0.3 psi
Equivalent Circulation Density[ECD]...	6.71 lb/gal (US)
Perforation Pressure.....	1898.0 psi g
Hydrostatic pressure loss.....	31.9 psi
Friction pressure loss.....	33.3 psi
Kinetic pressure loss.....	-0.6 psi
Restriction pressure loss.....	0.1 psi
Bottom Hole Pressure.....	1962.6 psi g
FROM CIRCULATION POINT TO WELLHEAD:	
Liquid transit time.....	20 min
Gas transit time.....	17 min
Annular volume.....	33.8 bbl

Open

Volume below circulation point.....	0.6 bbl
Total liquid volume.....	18.7 bbl
Total gas volume.....	15.6 bbl
(Surface equivalent).....	5551.4 scf
WORKSTRING:	
Liquid:	0.8000 bbl/min
Gas:	300 scf/min
Pressure at reel rotating joint.....	2807.3 psi g
Friction pressure loss on reel.....	937.5 psi
Hydrostatic pressure loss on reel.....	4.8 psi
Pressure inside WS at Gooseneck.....	1865.0 psi g
Hydrostatic pressure loss.....	-1115.4 psi
Friction pressure loss.....	1014.2 psi
Equivalent Circulation Density[ECD]...	0.50 lb/gal (US)
BHA total pressure loss	12.4 psi
BHA Hydrostatic loss	-0.6 psi
BHA Friction loss	4.5 psi
BHA Kinetic loss	1.4 psi
Nozzle	7.1 psi
Circulation Point pressure	1953.8 psi g
FROM REEL ROTATING JOINT TO CIRCULATION POINT:	
Liquid transit time.....	17 min
Gas transit time.....	17 min
Displacement Volume.....	20.5 bbl
Internal Volume.....	22.1 bbl
Internal liquid volume.....	14.2 bbl
Internal gas volume.....	7.9 bbl
(Surface equivalent).....	5096.5 scf
Length of Workstring on reel.....	1579.96 m

CTRAN SUMMARY

Project: Clean-out until top of plug Field-Well: Dulang - B16

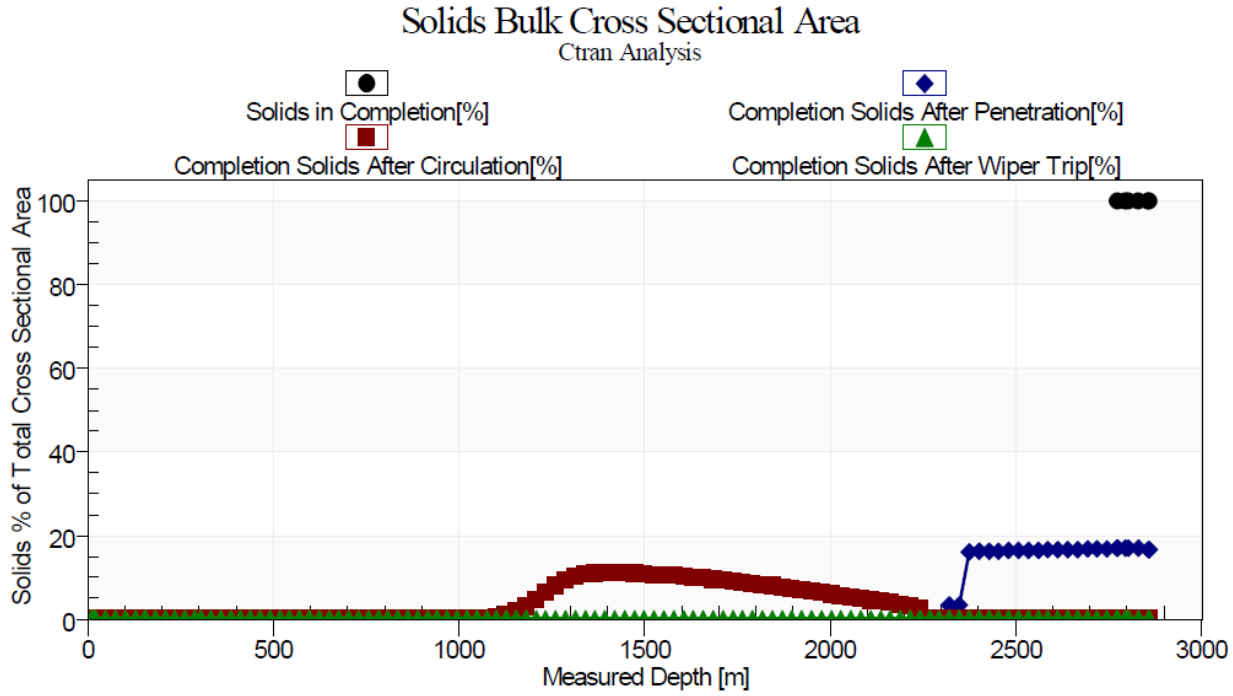
Ctran Summary

SUMMARY OF HOLE CLEANING RESULTS

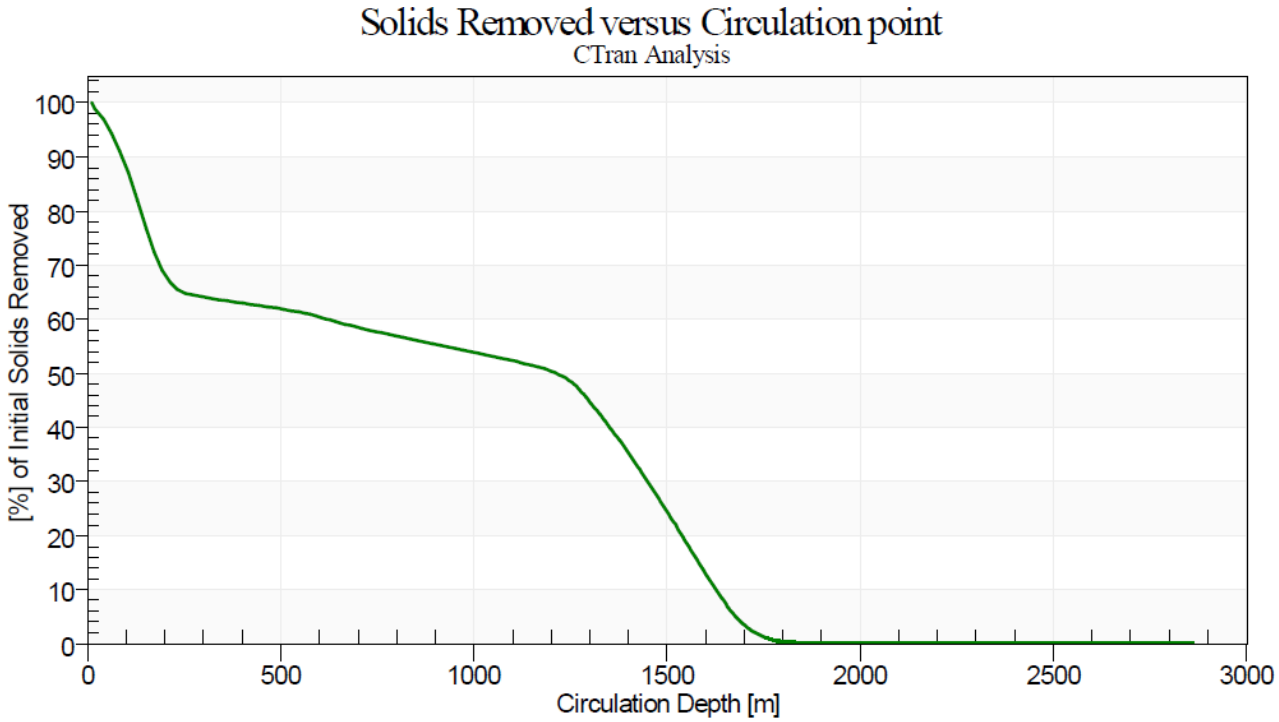
Initial Condition:	
% of fill interval occupied by solids before cleanout ...	100.0 %
Top of fill	2773.98 m
Deepest Circulation point	2860.00 m
Bottom of fill	2860.00 m
Initial Volume of Solids.....	1.6 bbl
Initial Mass of Solids.....	379.6 kg
Solids type:	Mud Residue/Formation Fines
Fluid Description:	Nitrified Water
Penetration Hole Cleaning Mode:	
Penetration rate.....	10.0 ft/min
Penetration time.....	0.47 hr
Solids volume in the well after penetration	1.6 bbl
Solids mass in the well after penetration	379.6 kg
Circulation Hole Cleaning Mode:	
Hole circulation time	3.00 hr
Solids volume in the well after circulation.....	1.6 bbl
Solids mass in the well after circulation.....	379.6 kg
Wiper Trip Hole Cleaning Mode:	
Wiper Trip Scheme:	Optimized rate, Tornado not used
Wiper trip time	4.02 hr
Solids volume in the well after wiper trip	0.0 bbl
Solids mass in the well after wiper trip	0.0 kg
Volume of Fluids Pumped During Penetration, Circulation & Wiper Trip:	
Gas volume	134854.3 scf
Liquid Volume	359.6 bbl
Penetration, Circulation & Wiper Trip time	7.49 hr
Circulation results at point of Maximum Solids Head:	
BHA Depth	318.18 m
Elapsed time	6.8434 hr
Wellhead Pressure	337.6 psi g
Additional Head created by Solids.....	42.6 psi
Maximum % solids circulated up hole was 35.5%.	
This occured at a measured depth of	730.00 m
after the transient had run for	6.5 hr

Open

SOLIDS BULK CROSS SECTIONAL AREA



SOLIDS REMOVED VERSUS CIRCULATION POINT



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APPENDIX VI – TUBING TALLY B16

CARIGALI

FIELD	DULANG B
WELL NO	B16ST3
DATE	15/01/2002

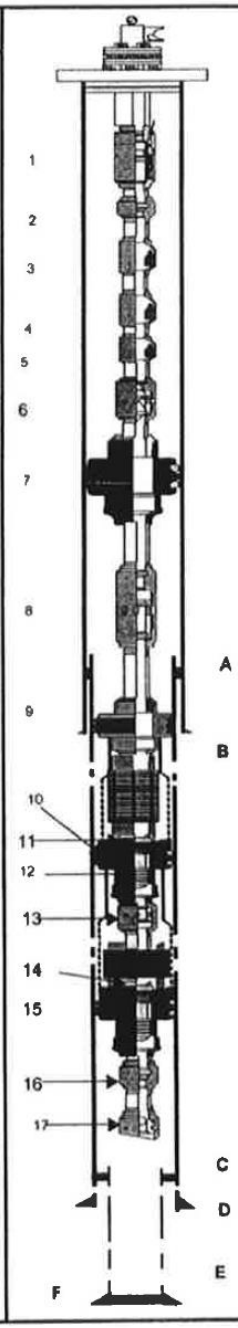
Schlumberger
COMPLETION REPORT

PAGE 1

	SIZE	WEIGHT	THREAD	GRADE	P/UP WT	S/OFF	BLOCK	COMPLETION TYPE
CASING	9-5/8"	47.0 ppf	BTC	N-80	43 K	10 K	HWO	SINGLE COMPLETION
LINER	7"	23 ppf	BTC	N -80	PACKER RELEASE 40 K ABOVE TUBING WT			
LINER	4.5"	11.6 PPF	TCIL	N -80				
TUBING	2-7/8"	6.4 PPF	VAM ACE	N -80				COMPLETION FLUID 9.0 ppG Surface filtered brine

COMPANY REPRESENTATIVE	COMPLETION ENGINEER	JOB TICKET NO
JIM HILLMAN / FAIZAL	SARAWAZAMAN / A.LATIF	DT21761

	DESCRIPTION	ITEM	DEPTH M	MIN I.D. IN	MAX O.D IN
	CAMERRON TUBING HANGER		CONTROL LINE PROTECTOR 16 EA		
	PUP JOINT				
	PUP JOINT	12 JT TBG	141.5	2.441	2.875
	PUP JOINT	1	154.900	2.313	4.550
	12 TUBING JOINT (VAM ACE)	13 JT TBG	276.596	2.441	2.875
	FLOW COUPLING	2	288.9	2.313	4.550
1	2-7/8" CAMCO TRSSSV TRM - 4A CX2-023 S/N:HSS-540	37 JT TBG	640.5	2.441	2.875
	FLOW COUPLING	3	653.9	2.441	4.375
	13 TUBING JOINT (VAM ACE)	48 JT TBG	1113.7	2.441	2.875
2	2-7/8" " CAMX- SELECTIVE NIPPLECQ2-025 S/N:HSN-0459	4	1127.09	2.441	4.375
	37 TUBING JOINT (VAM ACE)	51 JT TBG	1616.6	2.441	2.875
3	2-7/8" CAMCO SIDE POCKET MANDREL	5	1629.23	2.441	4.375
	C/W GASLIFT VALVE PTRO 845 PSLCT2-076				
	PORT SIZE 8/64 "S/R NO :361-HS6	6	1637.5	2.441	4.375
	48 TUBING JOINT (VAM ACE)	7	1645.46	2.441	8.465
4	2-7/8" CAMCO SIDE POCKET MANDREL	108 JT TBG	2687.7	2.441	2.875
	C/W GASLIFT VALVE PTRO 865 PSL CT2-076	8	2702.9	2.441	4.175
	PORT SIZE 3/16" "S/R NO :361-HS3	9	2727.165	3.880	5.875
	51 TUBING JOINT (VAM ACE)	2 JT TBG	2716	2.441	2.875
5	2-7/8" CAMCO SIDE POCKET MANDREL	10	2789.86	3.880	5.875
	C/W ORIFICE VALVE . CT2-077	6 JT TBG	2773.8	2.441	2.875
	PORT SIZE 16/64" SR NO: 870-HSS4	11	2786	2.441	3.350
6	2-7/8" SLIDING SLEEVE S/N: HSO-219 CM2-026	12	2786.29	2.441	3.300
7	9-5/8" BHR HYDRAULIC SINGLE PACKER	13	2794.6	2.313	3.210
	RETRIEVABLE SINGLE PACKER	5 JT TBG	2836.8	2.441	2.875
	108 TUBING JOINT (VAM ACE)	14	2850	2.441	3.300
8	2-7/8" SLIDING SLEEVE S/N: HSO-213 CM2-024	15	2862	3.880	5.875
9	7" WD GRAVEL PACK PACKER	5 JT TBG	2879.6	2.441	2.875
	2 TUBING JOINT (VAM ACE)	16	2880	2.250	3.175
10	7" WD GRAVEL PACK PACKER	17	2889.2	2.441	3.224
	6 TUBING JOINT SLIME LINE (VAM ACE)				
11	LOCATOR	A	TOP OF 7" LINER @ 1667mMD		
12	SEALS ASSY	B	9-5/8" SHOE @1867mMD		
13	2-7/8" SLIME LINE SLIDING SLEEVE	C	TOP OF 4-1/2" LINER @ 3001mMD		
	5 TUBING JOINT SLIME LINE (VAM ACE)	D	7" SHOE @3121mMD		
14	SEALS ASSY	E	PBTD @ 3189 M		
			MAX ANGLE: 80.18 DEG @ 1626m-MDDF		
15	7" WD GRAVEL PACK PACKER				
	2-7/8" PUP JOINT	F	4-1/2" SHOE @3223mMD		
16	2-7/8" " CAMXN- NO-GO NIPPLE EQ2#030 S/N: HSN-211				
	3 TUBING JOINT SLIME LINE (VAM ACE)				
17	CONICAL NOSE				
	PERFORATION INTERVAL E12/13 2760m-2784m				
	PERFORATION INTERVAL E14 2800m-2846m				
	PERFORATION INTERVAL E23 3060m-3070m				
	PERFORATION INTERVAL E23 3100m-3110m				
	PERFORATION INTERVAL E32 3160m-3170m				
	TOTAL SLIM LINE TUBING IN HOLE:14 JT				
	TOTAL TUBING IN HOLE:271 JT				



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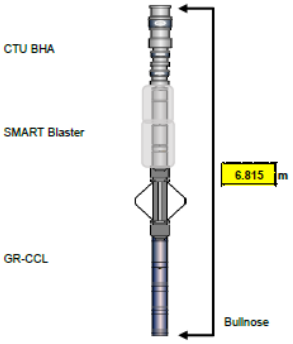
APPENDIX VII – TUBING CUTTER CORRELATION CALCULATION SHEET

GRCCL + HPT Run Toolstring



1. Cut Target Depth

2858.50 m DF

2. Uncorrected Flag Depth (Flag#3)

2858.50 m DF

3. Log Offset (base on GRCCL correlation)

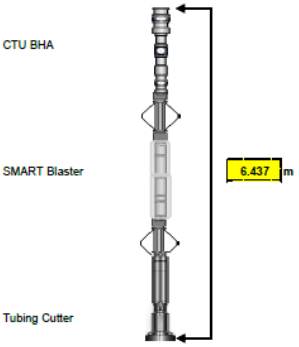
m

4. Corrected Flag Depth

2858.50 m DF + (Log Offset)

2858.50 m DF

Tubing Cutter Toolstring



5. CRP at Corrected Flag Depth

2858.50 m DF - GRCCL + HPT Run Toolstring

2851.69 m DF

6. Tubing Cutter at Corrected Flag Depth

2851.69 m DF + Tubing Cutter Toolstring

2858.12 m DF

7. Cable Movement

Target Depth - Tubing Cutter at Corrected Flag

2858.50 m DF - 2858.12 m DF

= 0.38 m

Open

APPENDIX VIII – 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 Coiled Tubing 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 Coiled Tubing).

   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 Coiled Tubing.
4. Set up to circulate well to kill fluid through the Coiled Tubing remaining in the well.
5. Make arrangements necessary to fish the Coiled Tubing 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 coiled tubing 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 coiled tubing to surface. Assess the scenario and consider all the risks associated then proceed to pull the coiled tubing 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 coiled tubing to surface.
5. If the leak is catastrophic, run the coiled tubing to HUD; pick up sufficient so that after the coiled tubing is cut at surface by CT BOP shear; the top of the coiled tubing falls below the X-mass Tree. Once the end of the coiled tubing is off bottom, proceed to cut the cut the coiled tubing 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 COILED TUBING AT SURFACE

In the event of a leak in the Coiled Tubing 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 Coiled Tubing reel.
2. If the leak is small or a pinhole leak, POOH and position the leak on the lower part of the Coiled Tubing 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 Coiled Tubing reel. Depressurize reel as much as conditions allow without exceeding collapse limitations of Coiled Tubing.
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 Coiled Tubing) set the Coiled Tubing 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 Coiled Tubing 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 COILED TUBING BELOW SURFACE

If a leak occurs in the Coiled Tubing below the Stuffing Box during down hole operations (usually indicated by a drop in pump pressure or loss of string weight), suspend Coiled Tubing 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 Coiled Tubing around the Injector Head and between the Injector Head and the Coiled Tubing reel.
2. Displace the Coiled Tubing 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 Coiled Tubing out of the Stuffing Box. Continue pumping water at a slow rate through the Coiled Tubing.
3. When the leak in the Coiled Tubing appears above the Stuffing Box, stop the injector and hold the leaking section of Coiled Tubing between the chains and the Stuffing Box.
4. Inspect leak. If leak is minor continue to POOH.
5. If leak is major, or Coiled Tubing is actually severed or well bore fluids are escaping through the Coiled Tubing, continue as per Section 09.2.

LEAK IN SURFACE PRESSURE CONTROL EQUIPMENT

Stuffing Box

1. **Stop** Coiled Tubing movement and close both sets of pipe rams to seal Coiled Tubing 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 Coiled Tubing should be clamped at the level wind and Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing is in riser and repair leak
2. Perform reinstatement test on surface equipment after leak has been repaired
3. If Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing is stuck down hole, pull to 80% of operating limit before activating Shear Seal BOP, thus allowing the Coiled Tubing to drop below the Xmas tree manual master valve. If the Coiled Tubing 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 Coiled Tubing to drop below the Xmas tree manual master valve. **If at all possible**, the decision to cut the Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing should be clamped at the level wind and Coiled Tubing 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.

COILED TUBING RUNS AWAY INTO WELL

If the inside chain tension system on the Injector Head should fail for any reason, and Coiled Tubing 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 Coiled Tubing.
3. Increase inside chain tension to increase friction on Coiled Tubing.
4. Increase stripper pressure to exert more friction on Coiled Tubing.
5. If these actions fail to make any difference, reduce injector hydraulic pressure to zero.
6. In the event that there is insufficient Coiled Tubing on the reel to reach bottom close Coiled Tubing slips. This action may damage or break the Coiled Tubing. 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 Coiled Tubing 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 Coiled Tubing on the reel to reach bottom.

   NOTE: Coiled Tubing may helix when hitting bottom making it difficult to pull into tail pipe.
8. Once Coiled Tubing has been controlled, examine Injector Head for damage including chains and POOH.
9. The Coiled Tubing run away may be caused by the injector becoming overloaded with the weight of the Coiled Tubing and fluid in the Coiled Tubing. This situation should not occur if proper pre job planning is done. Correct selection of Injector Head or ensuring Coiled Tubing is full of Nitrogen would prevent this situation from occurring.
10. If a run away 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 run away Coiled Tubing 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 Coiled Tubing comes to a standstill.

COILED TUBING IS PULLED OUT OF STUFFING BOX

This situation is most likely to occur when the Coiled Tubing 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 Coiled Tubing from passing through the Stuffing Box. If this situation occurs, stop injector before Coiled Tubing 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 Coiled Tubing at 300ft from surface. Slowly close in the swab valve counting the number of turns. If the Coiled Tubing is still deemed to be across the wellhead, POOH the Coiled Tubing no more than the distance between the top of the wellhead and the top of the Coiled Tubing 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.

COILED TUBING COLLAPSED AT SURFACE

Collapsed Coiled Tubing 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 Coiled Tubing due to its change in shape. Usually collapsed Coiled Tubing will not pull through the bottom brass bushings on the Stuffing Box.

1. If POOH, immediately run Coiled Tubing 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 Coiled Tubing internal pressure by circulating.
6. Once pressure conditions inside and outside the Coiled Tubing have been optimized, a decision can be taken on how to proceed. If it is not possible to position uncollapsed 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 Coiled Tubing.

   NOTE: If it is not possible to control the well, the slips will have to be set, and the Coiled Tubing cut using the Shear Seal rams.
9. Arrange for clamps to be fitted to Coiled Tubing 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 Coiled Tubing from the well using the Injector Head.
15. Cut Coiled Tubing at the gooseneck and use the rig or a crane to pull the Coiled Tubing through the injector. Re-clamp the Coiled Tubing above the Injector Head and cut off in thirty foot sections (or as appropriate to the crane or rig)
16. Continue pulling and cutting Coiled Tubing until the Coiled Tubing pulled to surface can be pulled by the Injector Head.

17. Once Coiled Tubing in good condition (i.e. not collapsed) is at surface, set Coiled Tubing slips and pipe rams and make up roll-on connector to Coiled Tubing 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.

COILED TUBING BREAKS AT SURFACE

If Coiled Tubing 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 Coiled Tubing reel.
5. If the reel capacity is insufficient to hold all of the Coiled Tubing remaining in the well due to uneven spooling resulting from the Coiled Tubing failure, it may be necessary to obtain another reel with sufficient capacity to hold the Coiled Tubing remaining in the well.
6. After consulting with client representative, remove damaged section of Coiled Tubing 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 Coiled Tubing still in the well, continue as per Section 0.

BUCKLED TUBING

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

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

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

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

If the Coiled Tubing is being run into casing and a large amount of weight is lost suddenly, there is a very good possibility that the Coiled Tubing 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 Coiled Tubing may have broken removing a restriction such as a BHA.
- A loss of string weight due to the Coiled Tubing breaking and falling off.
- An increase in string weight while pulling out of the hole as the buckled portion of Coiled Tubing creates additional drag or needs to be straightened to get through a restricted ID.

In the event Coiled Tubing buckling is suspected, the Coiled Tubing 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 Coiled Tubing is buckled close to surface, the buckled Coiled Tubing 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 Coiled Tubing inside the BOP. In this event, open the rams and try to put undamaged Coiled Tubing across the pipe and slip rams.
6. Make arrangements to kill the well and retrieve the remaining Coiled Tubing from the well.
7. If the buckled Coiled Tubing is down hole and cannot be pulled free, consult the client representative as he may want the Coiled Tubing left at TD prior to being hung off in the slip and Coiled Tubing rams.
8. Arrangements should be made to run Coiled Tubing cutter on wireline to retrieve the Coiled Tubing above stuck point.

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

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

If the Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing.
6. Cut the Coiled Tubing
7. Remove as much of the buckled Coiled Tubing as possible leaving any undamaged Coiled Tubing showing above the Stuffing Box intact so that it may be rejoined later.
8. Bleed the pressure from above the Coiled Tubing rams and undo the connection below the injector.
9. Slowly raise the injector until it is clear of the damaged Coiled Tubing.
10. Cut away any damaged Coiled Tubing, dress the Coiled Tubing and install an inline connector.
11. Run some fresh Coiled Tubing 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 Coiled Tubing suspended below the slips plus 2,000 lbf for friction or CERBERUS prediction, whichever is greatest.
16. Equalize the pressure across the Coiled Tubing 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 Coiled Tubing will have to be cut.

COILED TUBING STUCK IN HOLE PROCEDURES

There are various scenarios by which Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing became stuck.

In all of the above cases, the Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing is stuck. As a rule of thumb, the depth that the pipe is held at will be the extension of the Coiled Tubing (in feet) when pulled to 80% of yield divided by 0.002. This can be determined using CERBERUS.

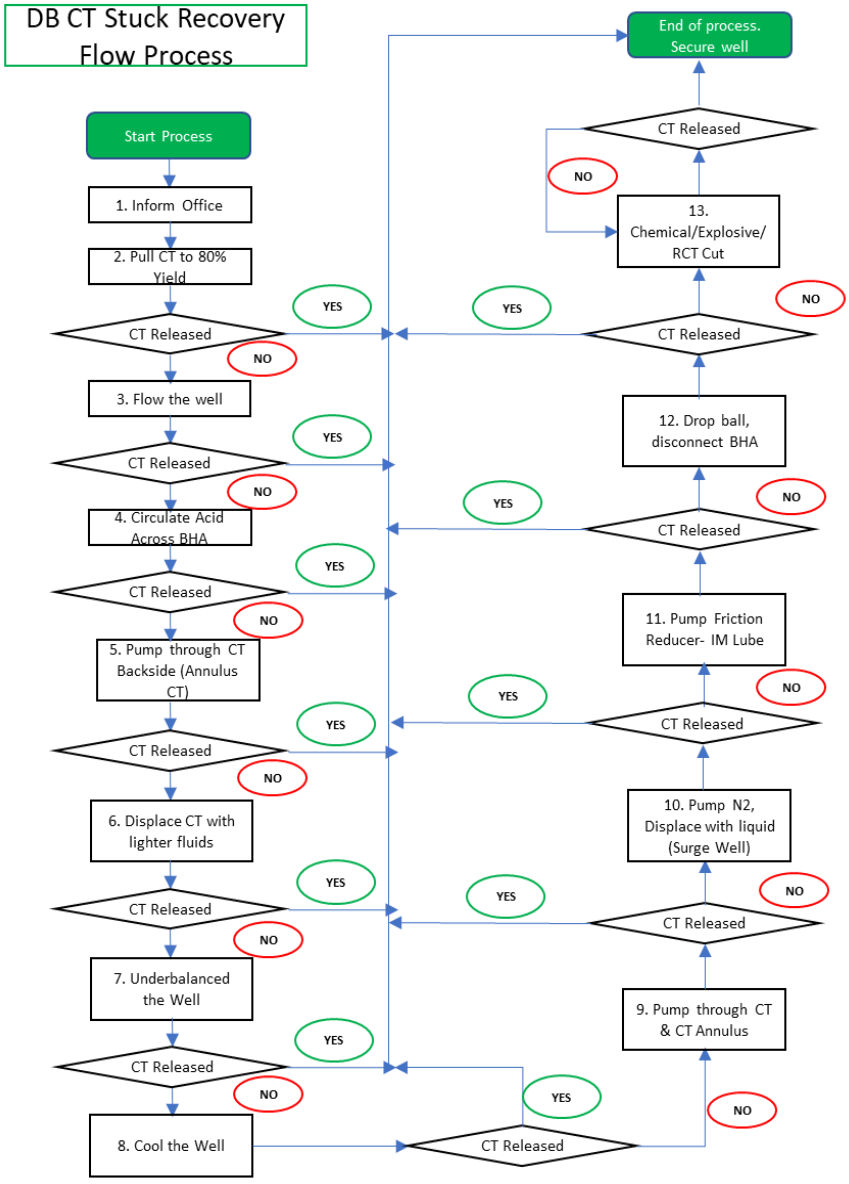
The following are options that may be appropriate depending on the particular circumstances:

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 Coiled Tubing/BHA. Maintain maximum circulation through the Coiled Tubing 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 Coiled Tubing.
3. Pump fluid down the backside of the Coiled Tubing to the formation in an attempt to dislodge debris from around the BHA. Potential Coiled Tubing collapse must be considered if engineering this scenario.
4. Displace Coiled Tubing 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 Coiled Tubing.
6. Cool the well if the Coiled Tubing is helically stuck in corkscrewed Production Tubing.

7. Pump down the Coiled Tubing / 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 Coiled Tubing 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 Coiled Tubing 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 Coiled Tubing violently across the gooseneck by frequent intervals.
12. The amount of cycles across the gooseneck must be logged, and if in doubt of the Coiled Tubing fatigue condition, the Engineer must be consulted and the cycles entered into the CERBERUS FATIQUE program, to determine the amount of cycles left available.

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

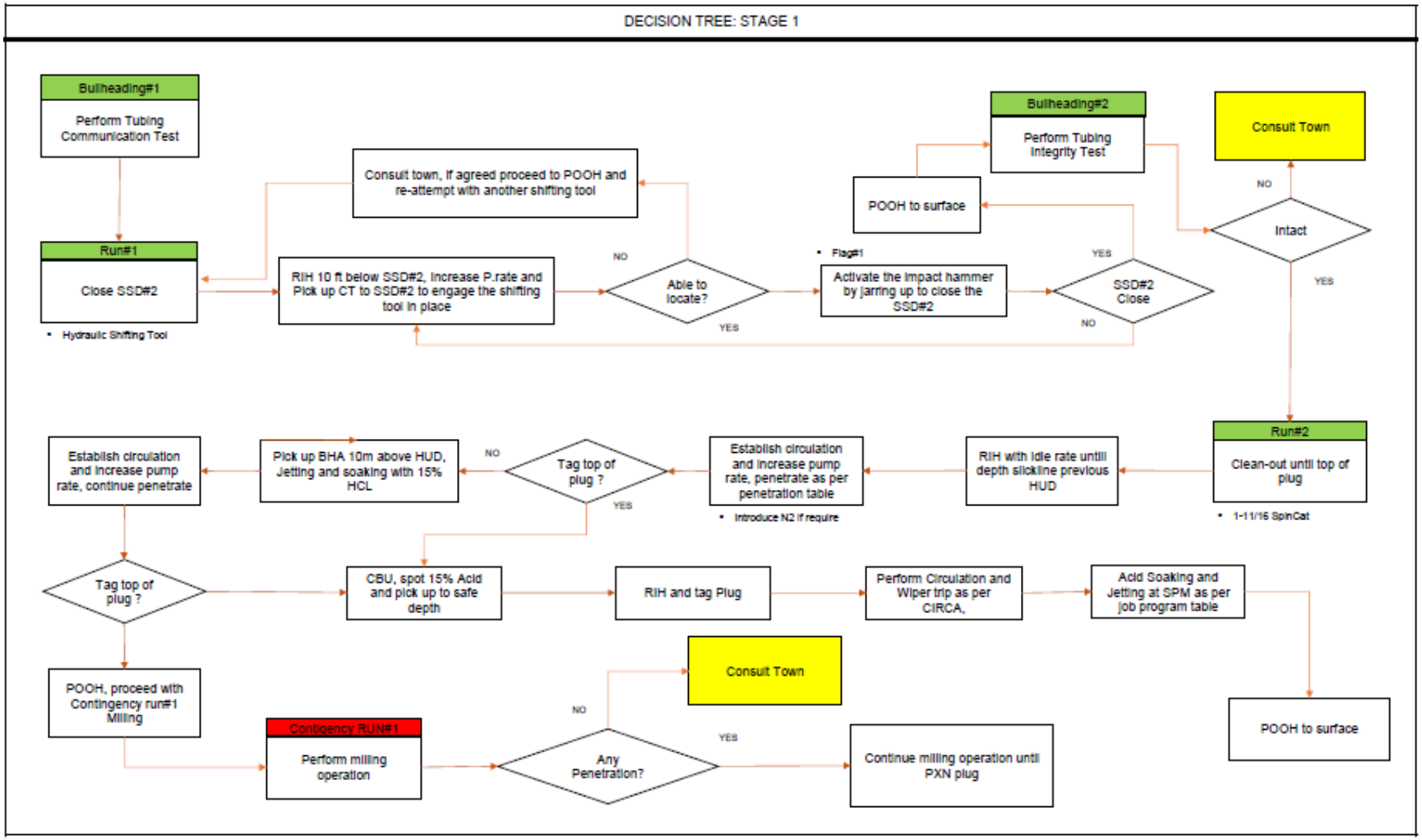
STUCK CT COIL RECOVERY PROCESS



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 IX – DECISION TREE 1st STAGE



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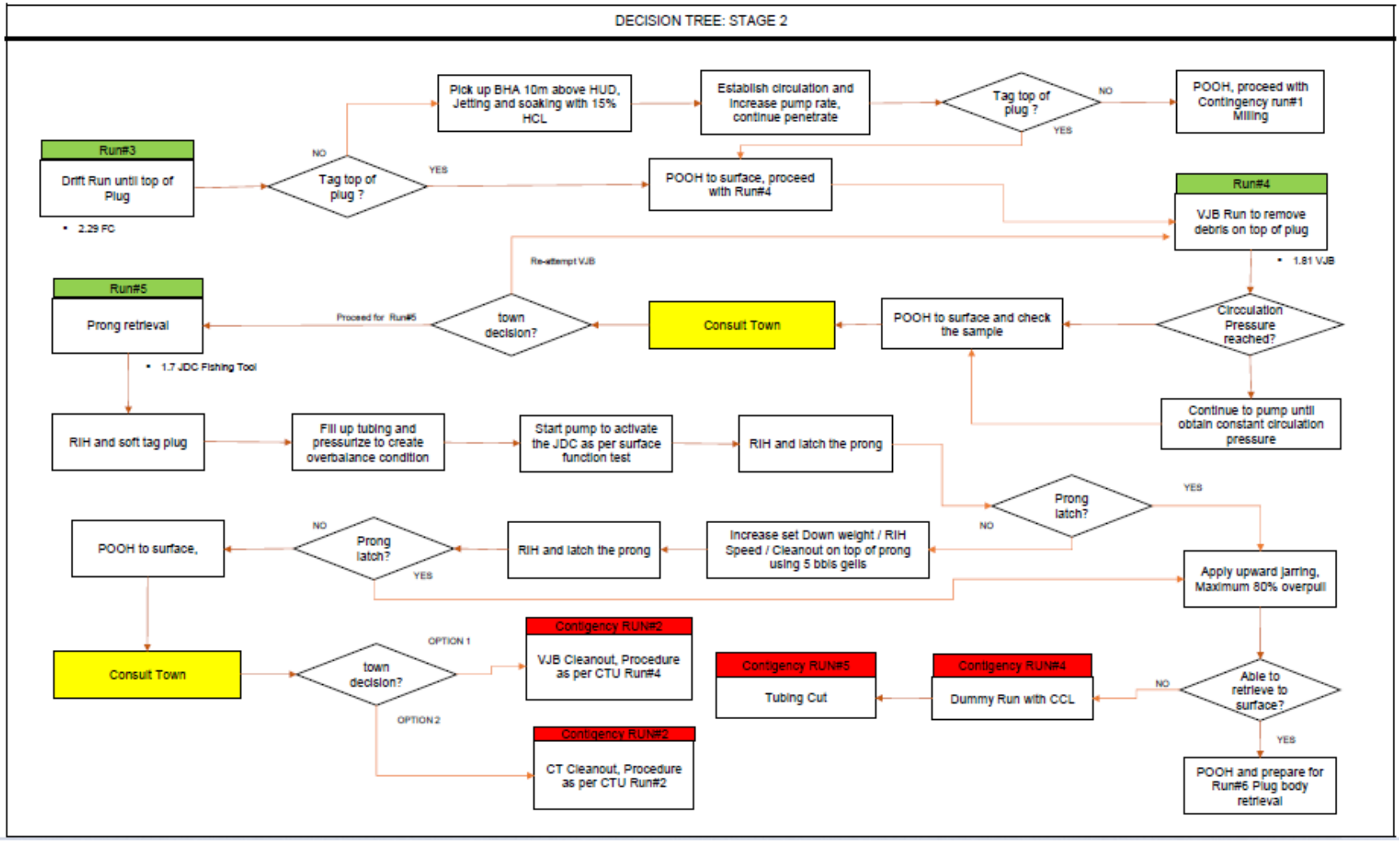
APPENDIX IX – DECISION TREE 2nd STAGE



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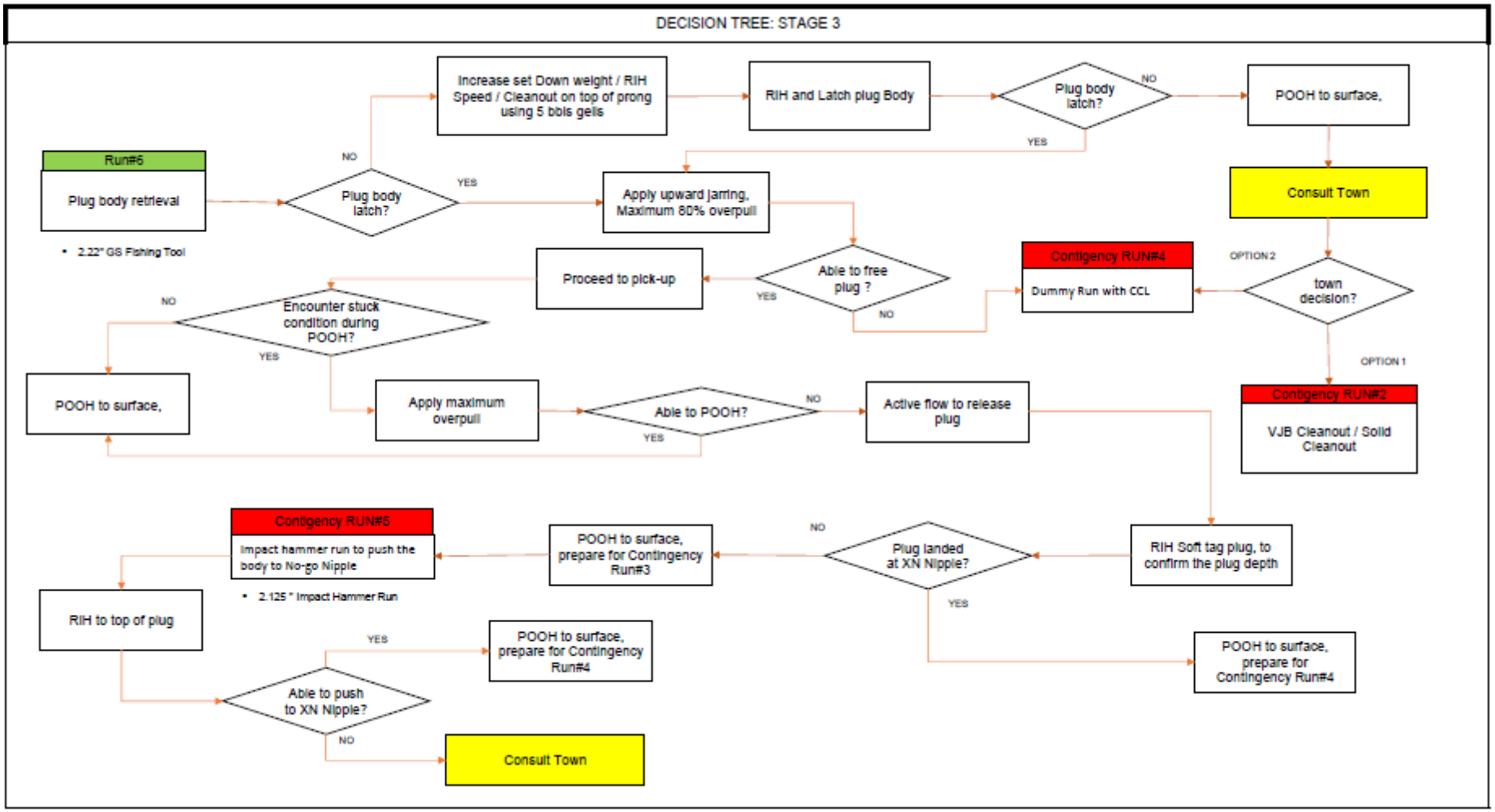
APPENDIX IX – DECISION TREE 3rd STAGE



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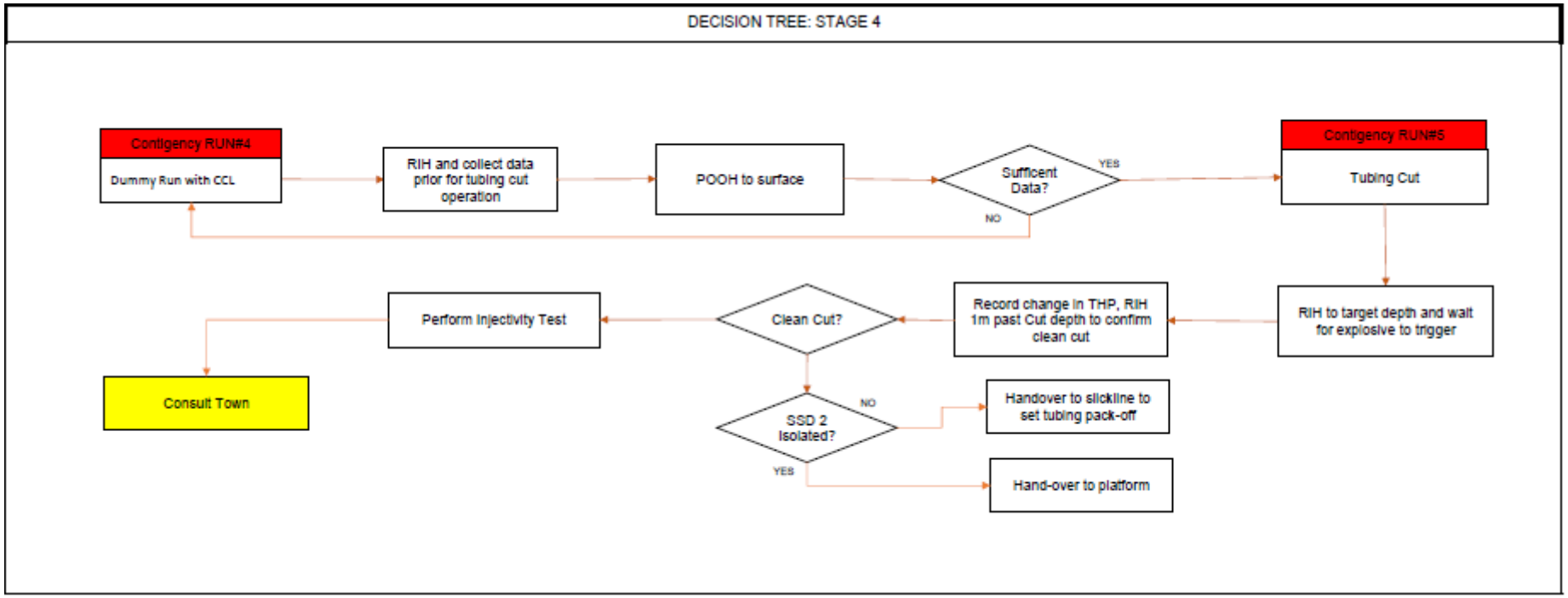
APPENDIX IX – DECISION TREE 4rd STAGE



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