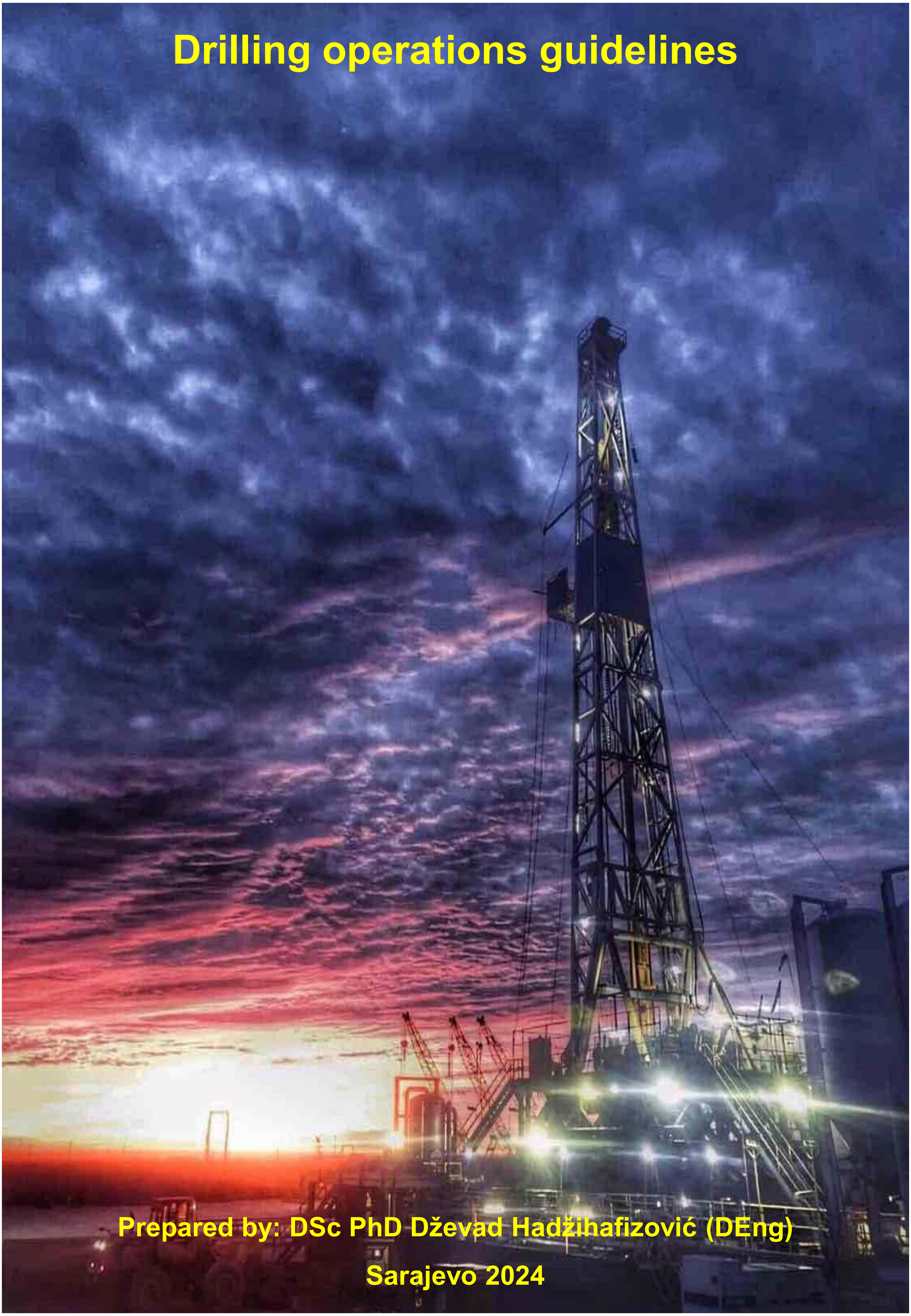
Drilling operations guidelines



Prepared by: DSc PhD Dževad Hadžihafizović (DEng)

Sarajevo 2024


DRILLING SUPERVISOR
Qualification
• These qualifications include: work experience, skills, specific knowledge, education level and type. professional licenses, personal qualities and attributes, languages, physical abilities etc.
Job Summary
• The job summary includes information like job title, department, division, importance of the job, job relationships, job duties and responsibilities, etc.
Skills Required
• Some skills are required for a particular job like communication, teamwork, problem-solving, initiative and enterprise, planning and organising, self-management, learning, technology knowledge etc.
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Table of Contents

DRIVING CONDUCTOR PIPE 40", 30", 20" AND 18 ⅝"

A minimum of one joint conductor pipe must be installed off-line while preparing the well site and prior to move the rig in. The size of the conductor pipe can be 40'', 30'', 20" or 18 ⅝" depending on the overall casing program.

1. Purpose

- To case off surface sand and unconsolidated formation.
- To facilitate installing diverter or bell nipple for drilling 36", 26", 24", 17 ½" or 16" holes.
- As barrier to mitigate corrosion of the surface casing.

2. Applications

- One joint of 40" conductor pipe is required prior to spudding 36" hole for setting 30" surface casing at 300 ft (heavy casing design).
- One or two joints of 30" conductor pipe is required prior to spudding 26" hole for setting 18 ⅝" casing at 300 - 500 ft (light casing design).
- Three to four joints of 30'' conductor pipe are run prior to drilling 26'' hole to top Dammam (heavy casing design).

3. Preparation

- On accepting the well location from the Production Operations, and after installing a pre-fabricated concrete "cellar", notify the concerned contractor of the conductor pipe job details, based on which the contractor will decide the type of drilling unit and crane to be employed.
- Ensure conductor pipe and accessories are ordered.
- Ensure the conductor pipe is coated with anti corrosion paint.
- Ensure cementing company is notified and cement is ordered.
- Ensure the opening of the concrete cellar is bigger than the "OD" of the temporary casing sleeve used by contractor to drill the hole.

4. Procedures

- A temporary piece of casing with approximate length of (20'-26’) will be placed through the center hole of the cellar, Figure 2-1.
- The contractor will select the diameter of this temporary casing depending on the diameter of the conductor pipe to be used.
- The temporary casing is placed by the driving unit.
- The driving unit is equipped with mounted drilling tool which can be an auger or drilling bucket. With this drilling tool, the temporary casing is excavated from the inside.
- During this excavation process, hole is drilled with bentonite mud mixed on site by the contractor.
- Drilling and excavation under the shoe level of the temporary casing is continued, while continuously mud is filled up to top level of the temporary casing.
- The drilling unit is capable of drilling to a depth of 200 ft. (5 joints).
- Run 30” OD stab-in shoe made up in the ADCO’s Drilling workshop, to the pin of the 1st joint conductor pipe.

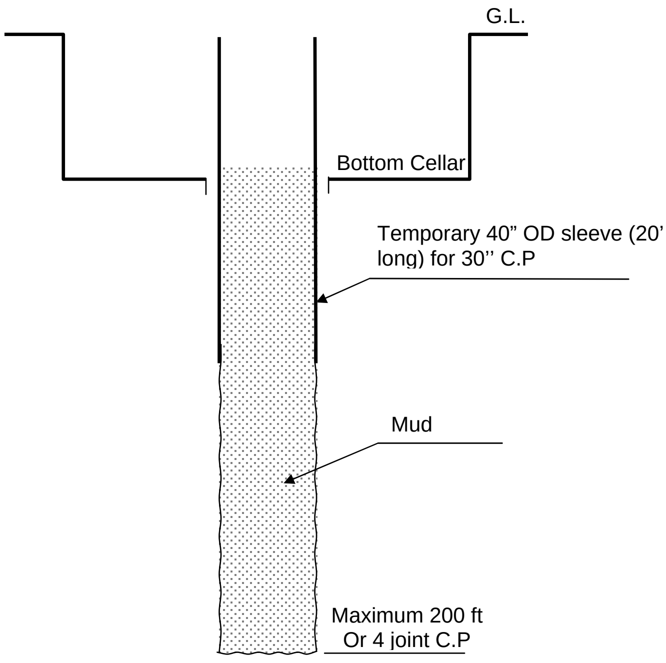


Figure 2-1: Running temporary sleeve & drilling hole prior to run C.P with piling machine

- Continue running conductor pipe to bottom.
- Adjust the stick up of the top joint to top cellar (GL).

- It is essential to centre conductor pipe prior and after cementing and to be in vertical position without deviation. A bullseye or any other instrument is to be used on the stick up to ensure the pipe is vertical.

- Conduct cement job immediately after running the pipe Figure 2-2.

- Recover temporary casing sleeve.

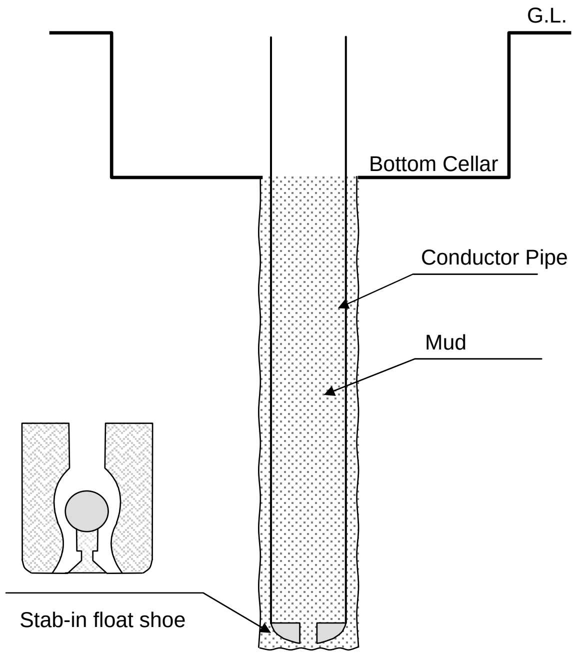


Figure 2-2: Conductor Pipe at Bottom Prior to Cementing

5. Cementing Conductor Pipe

Conductor pipe must be cemented to surface either by pumping cement slurry from top using 1 ¼" macaroni string run into the annulus, or by pumping through drill pipe and cementing stinger.

5.1 Cementing using 1 ¼" Macaroni String

This cementing method is applied in case of short conductor string (1 joint).

- Pump cement slurry through Y connection and two macaroni strings run as deep as possible to either side of the conductor pipe. Keep pumping until pure cement returns to surface.

- W.O.C for 4 hours, observe cement level in the annulus.

- Perform and repeat cement top job as necessary.

- Cementing equipment should stay on location until the annulus is confirming full of cement.

- Weld the proper adapter flange on top of the conductor pipe prior to rig move, this should suit the flange welded on the bottom of the mud riser, mud cross or diverter required for drilling next phase.

- The final level of the adapter flange should suit riser length and the flowline height of the Rig.

- Cover conductor pipe with steel plate.

5.2 Cementing through Stinger

This cementing method is applied in case of long conductor (2 joints and more). A stab-in float shoe should be run with conductor.

- Run cement stinger on drill pipe using crane.

- Fill conductor pipe with mud prior to sting-in.

- Sting into the shoe and slack-off all the DP weight.

- Circulate, ensuring the stinger is in place and is not jumping out of the shoe by observing no returns are coming from inside the C.P due to circulating pressure.

- Pump the cement down DP until pure cement returns to surface. Ensure no returns from inside the conductor throughout the job. Adjust pumping rate accordingly.

- Pull out DP and stinger. Wait on cement 4 hours.

- Carry out top job to fill the conductor pipe annulus as required.

Notes:

- Ensure open hole is free of steel or junk) do not run conductor pipe until this is fished out).

- Ensure the conductor pipe is clear with no junk inside.

- All necessary HSE precautions and observations must be applied all the time on location.

- Cement U-tube inside conductor pipe should not be allowed.

6. Wellhead

- Weld on top of conductor the following adapter flange as applicable:

In case of:	40” C.P.	38” flange
	30” C.P.	30” Landing Ring
	20 or 18 ⅝” C.P.	21 ¼“ flange

- Install 2” valve in the base of the exposed conductor pipe just above the cellar floor. This will be used to drain the conductor.
- Weld temporary 4 pad eyes to the conductor pipe stub to help supporting pipe during the next phase.
- Use proper steel plate with handles to cover the hole. Figure 2-3

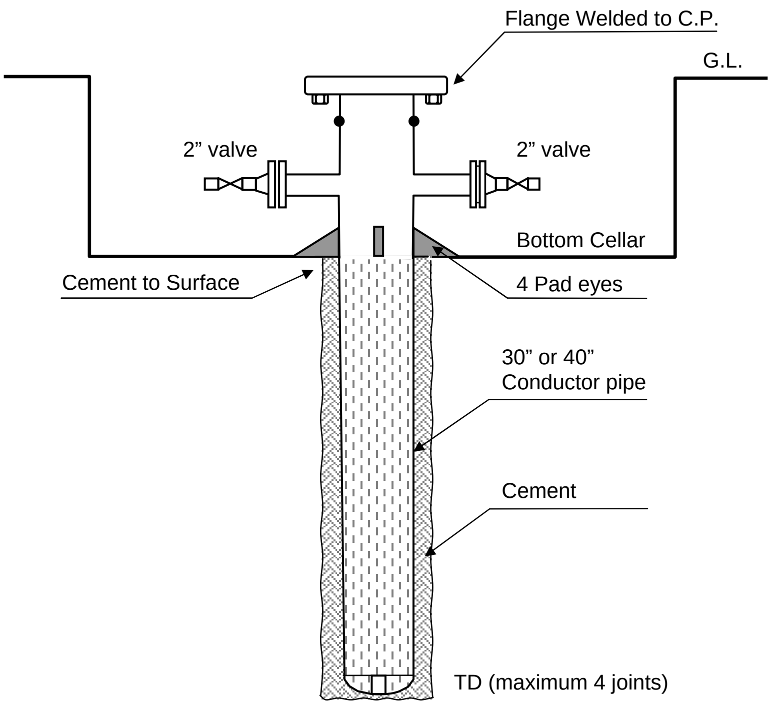


Figure 2-3: Conductor pipe with wellhead

36" HOLE FOR 30" CONDUCTOR PIPE

Drilling 36" hole is applied in Bu-Hasa field where 150 ft to 300 ft of 30" conductor pipe is installed prior to drilling 26" hole to top Dammam formation.

1. Purpose

- To case off surface sand and unconsolidated formation, prior to drilling Dammam formation.
- In case when 29 ½'' diverter is required while drilling 26'' hole, either pilling 30'' conductor pipe or drilling 36'' hole will be required.

Important Note:-

Drilling 36'' hole and running 30'' conductor pipe would require special safety awareness and precautions. It should be avoided whenever operationally possible.

2. Applications

36'' hole is drilled in Bu-Hasa field to 300 ft through one joint of 40" C.P Figure 2-4.

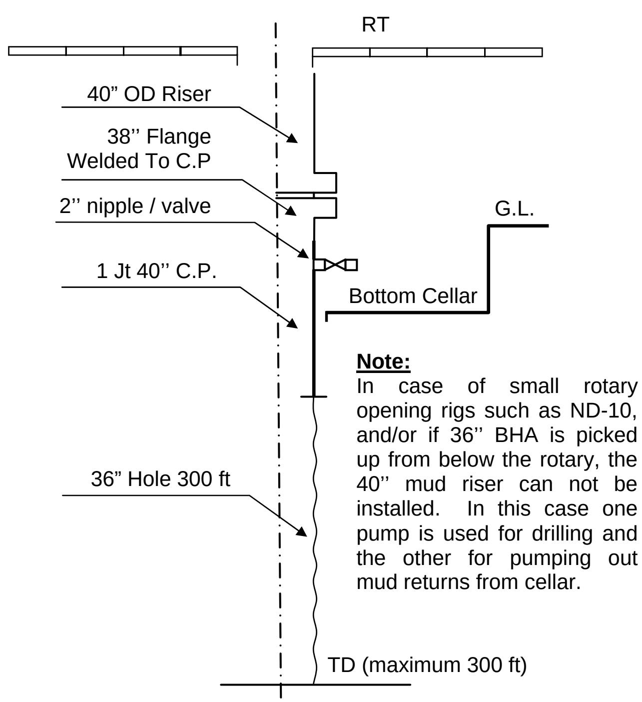


Figure 2-4: Drilling 36" Hole through 40'' Riser

3. Preparation

- Ensure 30'' conductor pipe and accessories are ordered prior to start moving the rig.
- Weld 38'' flange to the 40'' conductor pipe if required.
- Weld one or two 2'' OD nipples and valves on the stub of the 40'' conductor pipe just above cellar floor. This will be required to drain mud riser.
- Prior to spudding in, nipple up 40'' bell nipple and make up to the conductor if applicable Figure 2- 5.

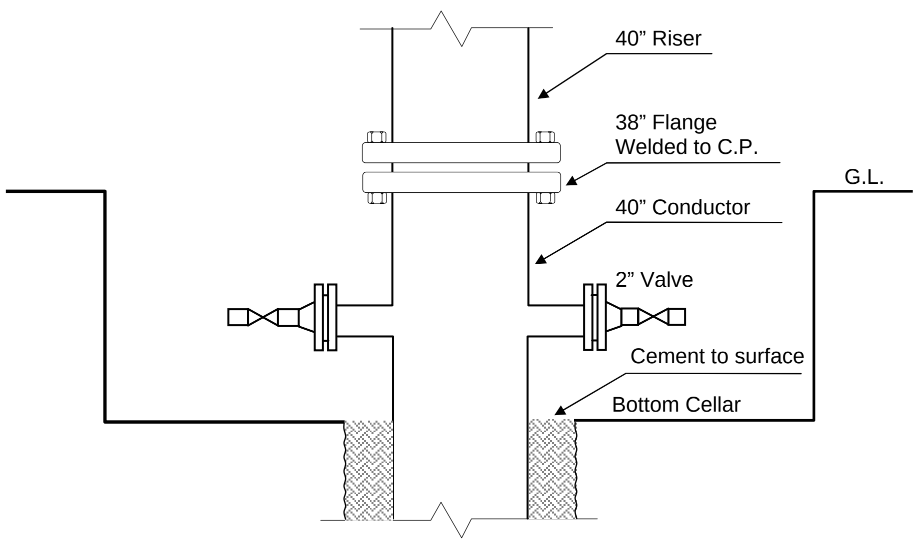


Figure 2- 5: 40" Conductor pipe while drilling 36" hole

- Change master rotary table bushing to 27'' split type, if required/applicable.
- Make up 36'' bit on BHA. Strap weld bit with bit sub.
- Whilst drilling 36" hole, prepare for running conductor pipe.
- Conduct safety meeting prior to start running C.P.
- Whilst POH with 36'' bit, pick up casing running equipment.
- Cut and L/D 40" riser prior to running the 30" conductor pipe.

4. Drilling

- Spud well and drill 36'' hole to casing setting depth + 5 to 10 ft sump.

- Recommended 36’’ BHA:

Table 2-1: Recommended 36” BHA

Option 1			Option 2		
Size	**Description**	**No.**	**Size**	**Description**	**No.**
36”	Bit	1	26”	Bit	1
36”	Near bit Stab	1	36”	Hole Opener	1
9.75”	Drill collar	2	9.75”	Bit Sub	1
9.75”	Crossover	1	9.75”	Drill collar	3
8.25”	Drill Collar	5	9.75	Crossover	1
			8.25”	Drill collar	1

- If a joint or more of 40’’ conductor was driven prior to spud, Clean out cement inside conductor; avoid washing out sand below shoe (Use one pump only).

- Drill 36’’ hole to TD. Adjust depth to suit casing length + 5 to 10’ sump.

- Special precautions must be taken to keep the Kelly straight and pipe in the center of the cellar opening. Due to the weight of Kelly hose, the Kelly will tend to push away from the side the hose. Weight of the Kelly hose must therefore be continuously supported by the air hoist while drilling the first 100 ft of hole. Remember a deviated surface hole will create problems throughout the well.

- Circulate hole clean and make wiper trip.

- Circulate hole clean, displace to viscous mud, drop Totco and pull out of hole.

5. Drilling Fluid

- Low Solid Non Dispersed Mud is used to drill this phase, see properties below:

Table 2-2: Mud properties required for drilling 36” hole

Density, pcf	**65 – 70** or as hole conditions dictates
Viscosity, sec/qt	45 – 55
YP, #/100 ft²	18 – 25
PV, cps	ALAP / 7 – 10
10 sec Gel , #/100 ft²	3 – 6
10 min Gel , #/100 ft²	8 – 12
API FL, cc/30 min.	N/C to 15 – 20 prior to running CSG
Drill Solids Content, %	< 6 (max.) LGS
Sand , % by Volume	Traces – 0.5 (Max.)
pH	9.5 – 10.5
Chlorides , ppm	60,000
MBT , ppb	20 - 25

- While drilling pump 50 bbls HVS every joint to assist in hole cleaning.

- At TD, sweep hole with 100 bbl high viscosity pill.

- Refer to Chapter-5 “Mud Guidelines” of this volume for more details.

6. Drilling Optimization

- Do not apply maximum parameter in the 1st 100 ft below conductor.
- Operate at the weight on bit and rotary speed that gave the highest penetration rate in the drill-off tests, unless significant losses problem is expected.
- Do not apply excessive weight on bit if “bit balling” or “bottom hole balling” have been identified as potential problems,
- Reduce the applied weight on bit and/or rotary speed as necessary to ensure that the penetration rate does not exceed the maximum allowable to maintain the hole clean and stable.
- Always use maximum possible pumping rate.
- Bit is usually run open.
- Balance flowrate to have 30% from hole opener and 60% from bit.

7. Running 30” Conductor pipe

- A special device “Landing Ring” is welded in DWS on one feet 30” nipple Figure 2-6.

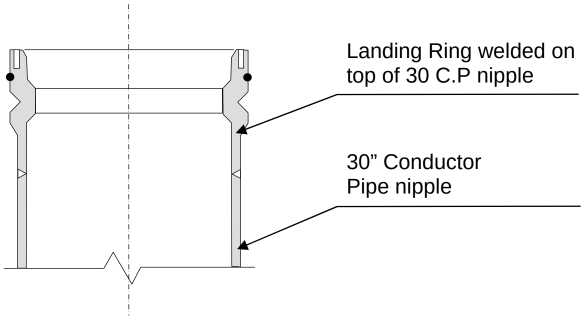


Figure 2-6: landing ring welded to the conductor pipe nipple

- Stab-in float shoe must be made up to the first conductor joint on ADCO’s Drilling workshop.
- Conduct safety meeting.
- Rig up casing handling equipment, run conductor pipe
- Flow check float shoe by filling the 1st joint of casing with mud, pull out then run back in and verify that level has dropped and no backflow is noticed.
- Install one centralizer on each conductor joints and one at 10 ft below cellar.

- Cut 40” C.P at bottom cellar prior running 30” C.P to allow installing the 30” heavy duty clamp at bottom cellar Figure 2-7.

Note: Special preparation (False R.T…) is needed on small rigs to run 30” C.P.

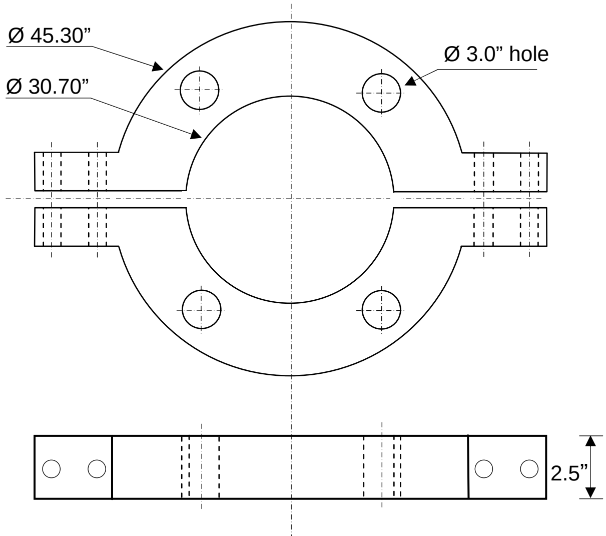


Figure 2-7: Heavy Duty Clamp for Landing 30” C.P. on Ground

- Space out to have bottom of the landing ring at 2 ft above bottom cellar to allow installing the clamp when shoe is at about 5 ft from bottom.
- Install heavy duty clamp, land conductor pipe (the clamp should grip on the body of the C.P so that not to expose the 30” conductor casing connector to downwards loads).
- Remove the clamp as cement set.
- Lay down landing joint.
- Make up landing ring assembly (with 1 ft conductor pipe nipple, pin bottom connection) on top of the 30” casing.

8. Cementing 30” Conductor

The 30” conductor should be cemented to surface using stab-in cementing system, Figure 2-8.

- Run the cementing stab-in stinger (after checking compatibility of stinger with shoe and condition of seals) on 5" drill pipe. (Fit drill pipe centralizer 10’ above the stinger).
- Break circulation before stinging into the float collar. Stab in and set down 3,000 lbs of DP weight. Continue to circulate, increasing rate to 400 GPM.

Check that no returns are coming from the DP/casing annulus and continue to observe for this throughout the cement job.

- Pump 300 Bbl low Viscous Mud followed by 50 Bbl of location water.
- Mix and pump cement slurry as per ADCO Lab formulation.
- Continue to pump cement until pure cement returns to surface. Displace cement to 100 ft above shoe or underdisplace by ±2 bbls. Sting out, check for backflow, if ok, POH stinger.

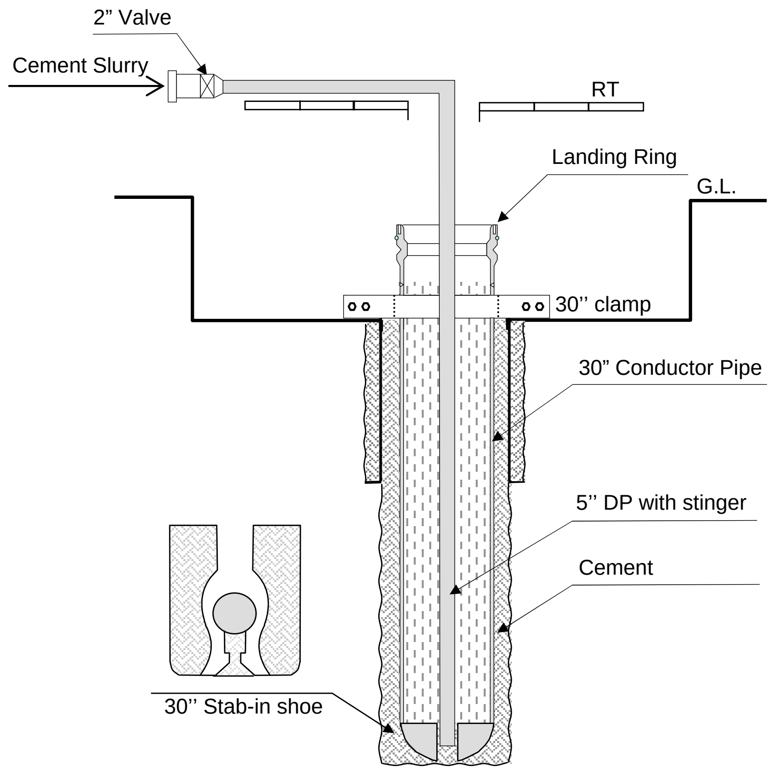


Figure 2-8: Cementing 30" Conductor Pipe with cementing stinger

8.1 Cementing Top Job

If losses were encountered, cement did not return to surface, or float equipment failed:

- Wait on cement 6 hrs.
- RIH two Macaroni pipes through the clamp, at different sides of the casing annulus, to top of cement or to the maximum depth reached.
- Mix and pump 125 pcf neat cement as top job until annulus is full with cement Figure 2-9.

- Handover the well to production operations requires that cement fills annulus.

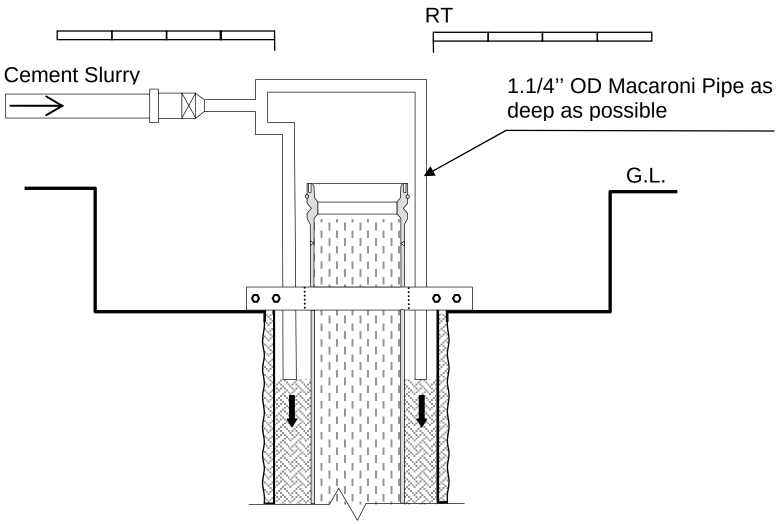


Figure 2-9: Cement Top Job with macaroni tubing

9. Wellhead

A special device “Landing Ring”, equipped with quick latch and loading shoulder is welded on top of the 30” conductor pipe to facilitate carrying out the following operations:

- Connecting mud riser to the conductor pipe for drilling 26” hole.
- Quick installation of mud-cross or mud riser using a flanged adapter assembly.
- Sealing-off 30” x 18 ⅝” annulus.

Note:

The “landing ring” should be welded to a 30” conductor pipe pup joint in the drilling workshop (1 ft pin bottom connection nipple).

9.1 “Landing Ring” Installation

- Make up last conductor pipe joint and land at the required depth on 30” heavy duty clamp using a landing joint, Figure 2-10.
- Lay down landing joint.
- Screw-in landing ring and pup joint on top of 30” conductor pipe. Figure 2-11.
- Cement 30” conductor pipe through inner string.

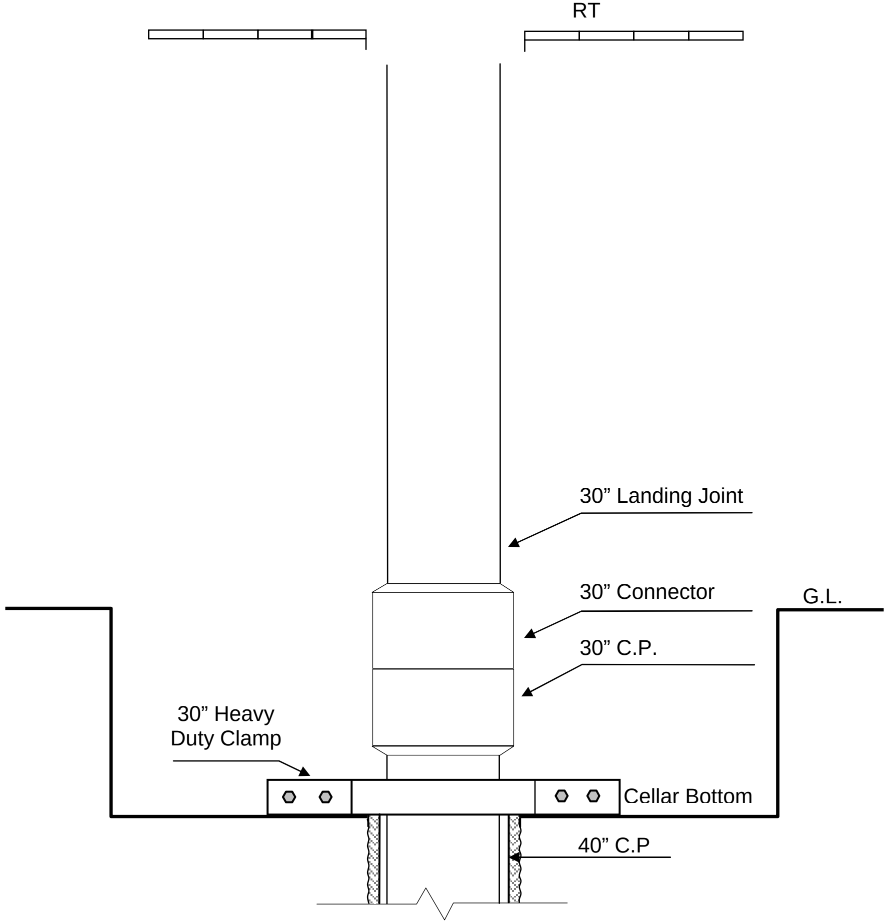


Figure 2-10: 30” Conductor pipe landed on clamp using landing joint

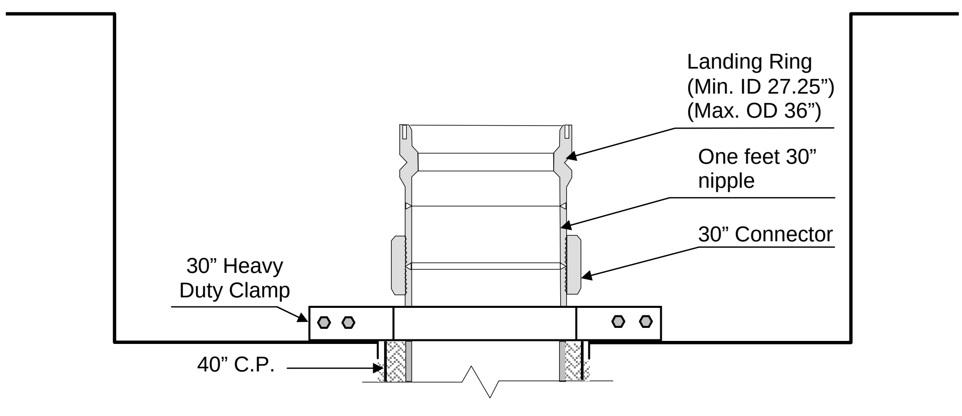


Figure 2-11: landing ring and one ft nipple made up to the C.P prior to cementing

10. Blowout Prevention

26” hole is drilled through 30” mud riser or 29 ½” x 500 psi diverter.

10.1 Drilling through Mud Riser

Make up the adapter assembly (welded to a 30” riser), lower until shouldered onto the landing ring and secure using the Hold Down Screws. Figure 2-12.

10.2 Drilling through 29 ½” Diverter

- Nipple up mud cross 29 ½” diverter system on adapter assy 29.5” – 500 psi. Figure 2-13. Connect valves, vent line and kill line).
- Pressure test the system to 200 psi before installation.
- “Open – Close – Open” function test and synchronization of the system (diverter/vent line valve) is to be performed.

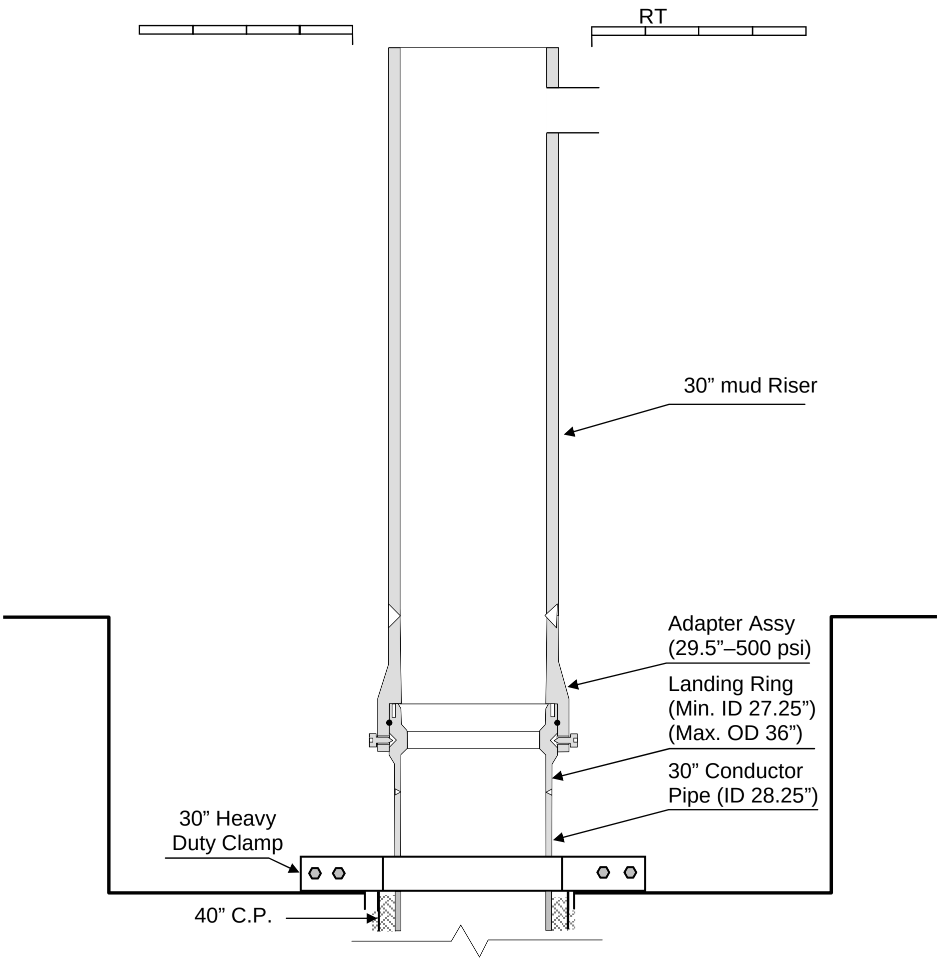


Figure 2-12: 30” Riser for drilling 26” hole

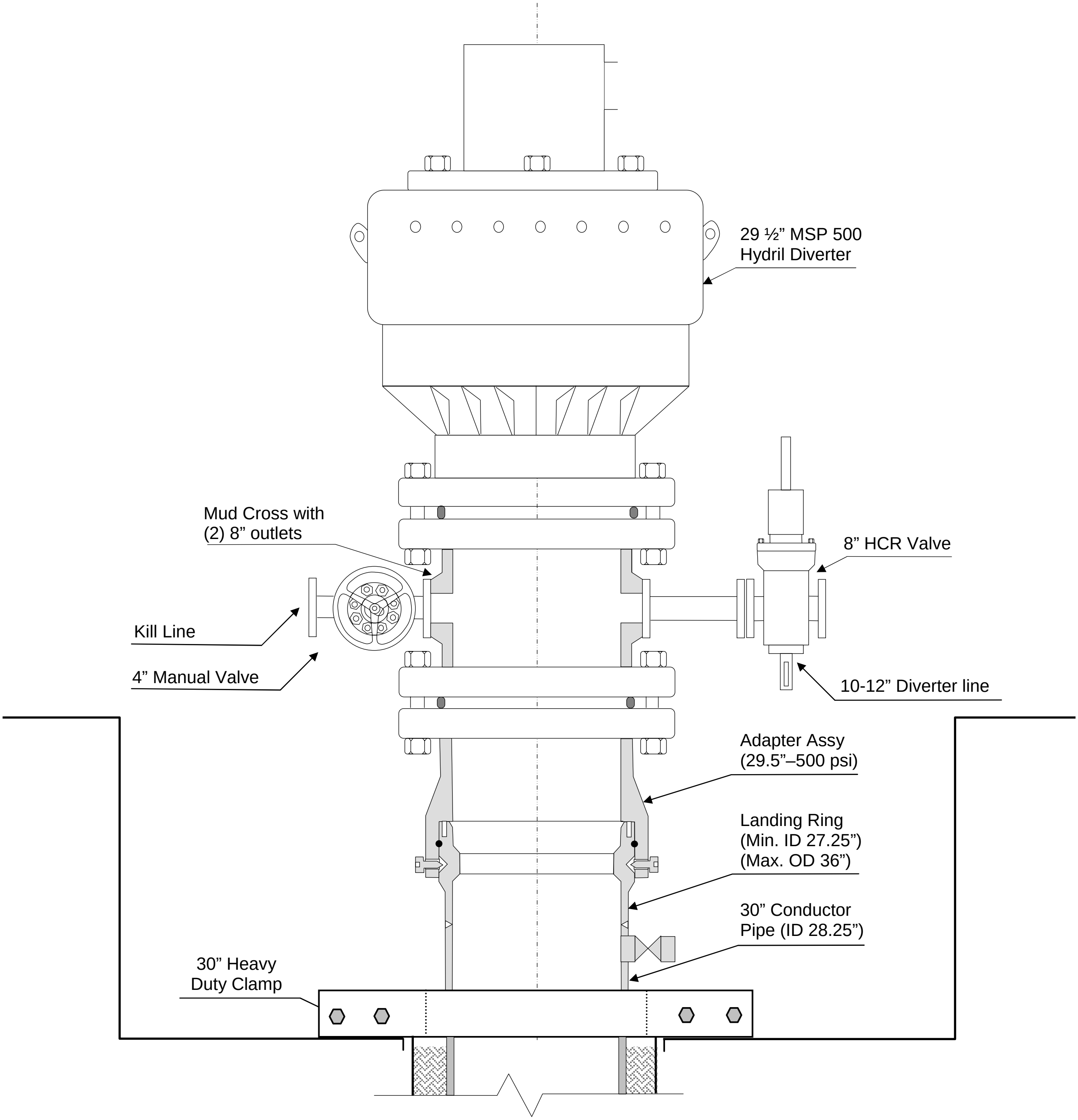


Figure 2-13: Diverter stack for drilling 26" hole

11. Equipment

11.1 40” Conductor Pipe

Mesc No. 0401806979

Dimensions and mechanical properties of 40” conductor pipe are as follows:-

Table 2-3: 40” conductor pipe properties

Characteristics	40” Casing
Body OD (in)	40
Grade	X-52
Weight (lb/ft)	417
Connection	Welded
Min. ID (In)	38
Capacity (Bbls/ft)	1.403

11.2 30” Conductor Pipe

Mesc No. 0401805299

Dimensions and mechanical properties of 30” conductor pipe are as follows:

Table 2-4: 30” Conductor pipe properties

Characteristics	30” Casing
Body OD (In)	30
Grade	X-52
Weight (lb/ft)	272
Connection	Connector
Min. ID (In)	28.25
Drift diameter (In)	28.049
OD of coupling (in)	31.625
Capacity (Bbls/ft)	0.775
Body yield strength (klb)	4483
Coupling yield strength (klb)	2330
Collapse pressure (psi)	1220
Burst pressure (psi)	2940

11.3 Conductor Pipe Connector

- Two connector pieces (pin and box) to be welded on both 30” conductor pipe ends in the Drilling workshop.

Connectors sealing is ensured by internal and external shoulders.

Dimensions and mechanical properties for 30” connector are shown below:

Table 2-5: 30” Conductor pipe connector properties

Characteristics	30” Connector
Grade	X-60
Weight (lbs)	583
Min. ID (In)	28.250
Max. OD (In)	31.625
Capacity (Bbls/ft)	0.775
Make up Length (In)	16
Body yield strength (klb)	2230
Burst pressure (psi)	800

11.4 Other Equipment

Table 2-6: 30” Conductor pipe and accessories

S.N.	Description	Grade	Wt lb/ft	Thread	MESC No.
2	Casing Connector	X-60	583	Connector	0402261909
3	Stab-in Shoe	X-52	-	Connector	0514175129
4	O.H. Centraliser	-	-	-	0402269909
5	Stop Collar	-	-	-	0402261729
6	Landing Ring			-	

12. Waste Management

Hole Size	Mud Salinity	Rental Equipment		Mud Handling	Cuttings Handling
36"	Water Base Mud	**Tanks**	**4**	**NO DUMPING** Excess mud to be transported to injection disposal well.	Cuttings to be piled on location and to be used to bund the location.
		Centrifuge	**1**		

26” HOLE FOR 18 ⅝” CASING

The setting depth for 18 ⅝” casing is based on the history of each field, but its main purpose is to isolate the soft loose and unconsolidated formations where static losses and water flow may occur.

1. Purposes

- Protect useable surface water from contamination.
- Set deep enough so formation integrity can handle water flow / loss at potential 17 ½” section TD.
- Support blowout preventer, wellhead and subsequent casing strings.

  This hole section is associated with a number of problems mainly hole cleaning, loss circulation, sand caving which are all relating to the nature of the surface unconsolidated formation and the large hole size that requires high pumping rate to keep hole clean and full. Contingency plan must be in place to address each individual potential problem (Refer to GWP for specific precautions required in each field).

2. Application

18 ⅝” casing is set at shallow depth into Miocene formation, or deeper into top Dammam, This could be either vertical or deviated depending on the application.

- Set shallow 300 to 600 ft to case-off the surface unconsolidated formation prior to drilling Dammam formation (light casing design).
- Set deep at 100 to 200 ft into top Dammam to case-off Miocene formation, prior to drilling UER and Simsima formation (heavy casing design).

The drawings below show the different applications of the 18 ⅝’’ casing in each field:

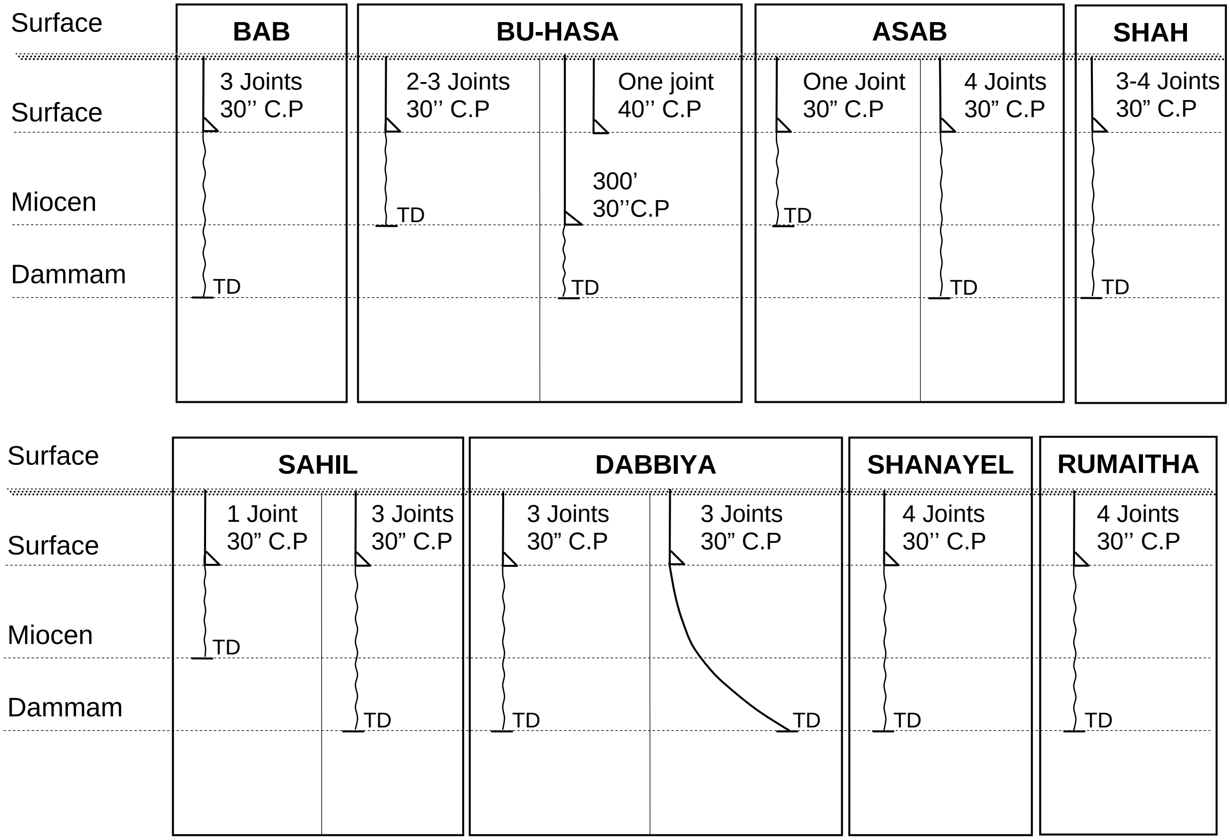


Figure 2-14: ADCO's Typical 26" Phase

3. Preparation / Off-Line Operations

- Ensure 18 ⅝" casing and accessories are ordered prior to start drilling 26'' hole.
- Prepare 18 ⅝" casing, install centralizes.
- Make up and threadlock float shoe to the first 18 ⅝" casing joint and stab-in float collar on top of the second joint only. Tag weld shoe and float collar to the 18 ⅝" casing.

  Note: Stab-in shoe is enough if casing depth is 300 ft or less

- Whilst drilling 26" hole, prepare for nippling up BOP's.
- Whilst pulling out of hole with 26'' BHA, pick up 18 ⅝" casing running equipment.
- Lay down 26" BHA.
- Pick up and stand in derrick the 5' DP required for cementing 18 ⅝" casing.

- Prepare cellar pumps and lines to transfer mud and cement returns from cellar to shale shakers or waste tank.

4. Drilling

- 26’’ hole will be drilled through 30” OD mud riser or 29.1/2” - 500 psi diverter, Figure 2-15 and Figure 2-16.

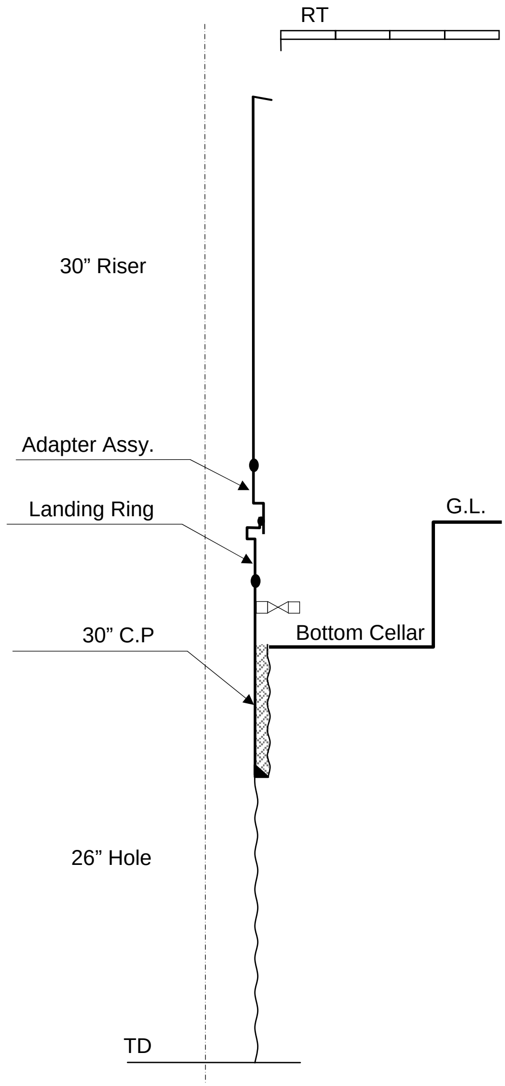


Figure 2-15: Drilling 26” Hole through 30” Riser

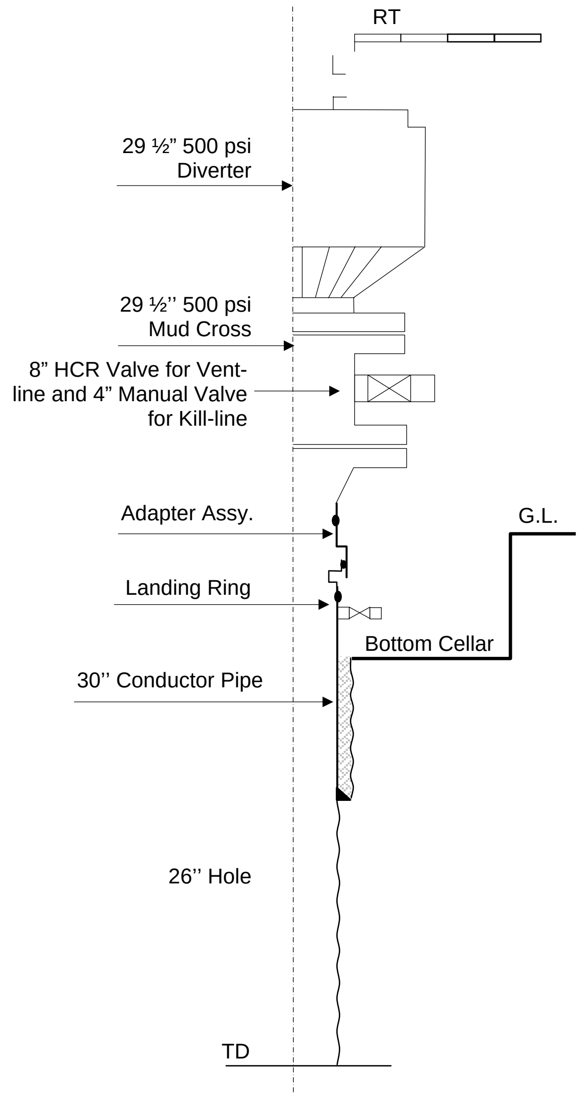


Figure 2-16 : Drilling 26” Hole through 29 ½” Diverter

- The following 26” drilling assemblies will be used to drill out this section.

Table 2-7: Recommended BHA for 26” Hole

Shallow 26” Hole Rotary drilling			26” Hole to ±1500 ft Motor drilling		
Size	Description	No.	Size	Description	No.
26”	Rock bit	1	26”	Bit	1
9.75	Bit sub	1	9.5”	Motor w/26” sleeve stab	1
9.75”	Drill collar	1	26”	String stabilizer	1
26”	String stabilizer	1	9.5”	Drill collar	1
9.75”	Drill collar	1	26”	String stabilizer	1
9.75”	Drill collar	1	9.5”	Drill collar	1
9.75”	Cross over	1	9.5”	Cross over	1
8.25”	Drill collar	6	8”	Drill collar	9
8.25”	Cross over	1	8”	Drilling jar	1
			8”	Drill collar	3
			8”	Cross over	1
			5”	HWDP	12

- Whenever picking up drill collars, stabilizer or substitutes, follow the normal practice of checking and recording ODs, IDs and lengths, particularly of fishing necks on each and every item.

- The BHA should be designed to be as simple as possible.

- The assembly will contain two string stabilizers (in deep 26” hole), to ensure hole is reamed and best wellbore geometry is obtained.

- A float valve is to be installed in the string.

- Clean out 30’’ conductor pipe, drill 26” hole to total depth.

- Drill the section at optimum ROP’s.

- If increasing resistance is experienced during tripping out (that cannot be wiped free.) the assembly will be pumped out of the hole monitoring drag and pump pressure (watch out for loss circulation).

- If excess overpull is experienced, wiper trip to be performed prior RIH with casing.

- Circulate hole clean using 50 bbls viscous pill. Pull out of hole and run back to bottom, Flush the hole with 50 - 100 bbls high viscous pill, viscosity of 120-150 sec/qt periodically.

- Drop Totco and pull out of hole for casing.

Note:

Miocene Clastics contains interbeds of soft sand and gravels that should be monitored during drilling.

5. Drilling Fluid

Water Base Low Solid Non Dispersed Mud (LSND) is normally used in all fields except for Dabbiya and Rumaitha fields where KCL/XC-Polymer Mud is used during drilling the deviated sections.

1) Low Solid Non Dispersed Mud properties:

Table 2-8: Low Solid Non Dispersed Mud Properties

Density, pcf	**65 – 70** or as hole conditions dictates
Viscosity, sec/qt	45 – 55
YP, #/100 ft²	18 – 25
PV, cps	ALAP / 7 – 10
10 sec Gel , #/100 ft²	3 – 6
10 min Gel , #/100 ft²	8 – 12
API FL, cc/30 min.	N/C to 15 – 20 prior to running CSG
Drill Solids Content, %	< 6 (max.) LGS
Sand , % by Volume	Traces – 0.5 (Max.)
pH	9.5 – 10.5
Chlorides , ppm	60,000
MBT , ppb	20 - 25

2) KCL/XC-Polymer Mud Properties:

Table 2-9: KCL/XC-Polymer Mud Properties

Density, pcf	72 - 75
Viscosity, sec/qt	45 – 55
YP, #/100 ft²	18 – 25
PV, cps	ALAP / 7 – 10
10 sec Gel , #/100 ft²	3 – 6
10 min Gel , #/100 ft²	8 – 12
API FL, cc/30 min.	10 – 12
Drill Solids Content, %	< 6 (max.) LGS
PH	8.5 – 9.5

Refer to Chapter-5 “Mud Guidelines” of this volume for more details about drilling fluid.

6. Drilling Optimization

- Operate at the weight on bit/rotary speed combination that gave the highest penetration rate in the drill-off tests, unless significant losses problem is expected.

- Proper and correct drilling practices must be exercised to ensure that hole quality and prevention of washout and enlargement could be adequately managed at the rig site through instituting proper drilling practices.

- Do not apply excessive WOB if bit or BHA balling have been identified as potential problems.

- Use reduced pumping rate immediately after spudding to avoid washout below conductor pipe, but after drilling 30 ft. increase pump rate to maximum. The use of viscous pills before connections will help clean the hole.

- The maximum allowable penetration rate, beyond which the ECD exceeds the leak-off pressure, due to cuttings loading in the annulus, should not to be exceeded.

- Bit selection will be as outlined in well program, usually IADC Code 111, for rotary drilling and 115 for motor drilling.

- Maximise jet impact force to ensure that bit, teeth/inserts and bottom of hole are maintained cleaned. Use maximum available energy from mud pumps.

- At TD, flow rate should be 1100 to 1200 gpm, Hydraulic>350 ft/sec and TFA 0.8-1.0.

- Consider using center nozzle for better bit cleaning.

- Clearing drilled cuttings from the bits and hole openers is paramount in large hole sizes.

- Sweeps must be pumped often and of sufficient size (40 – 60 bbls) to keep bit and BHA clean.

- Do not drill with one pump.

- Utilize ROP log from nearby wells for ROP and formations tops references.

- Rotate pipes at speeds around 120 rpm (lower speeds can be used in small hole sizes).

- Avoid BHA components that will not allow the hydraulic and hole cleaning procedures to occur.

- Don't POH while pumping out at higher rate than the circulation rate being used.

- Rotate at high RPM, and work pipe slowly, while pumping at maximum flowrate to clean up hole prior to tripping.

- Minimum use of back reaming and down reaming.

- If tight hole is encountered on a trip, first assumption should be cuttings.

- Monitor hole conditions using torque, drag and pressure data to ensure that ROP does not exceed hole-cleaning rate.

- Focus on daily penetration rate, not instantaneous ROP.

- Monitor fill and report on check trip.

7. Running 18 ⅝" Casing

- Lay down bell nipple and/or diverter.
- Make up, threadlock and tag-weld float shoe and float collar on the first and second casing joints on pipe rack (for shallow 18 ⅝" casing use only stab-in shoe).
- Install centralizers on pipe rack as follows:

  5 ft above the shoe (over stop collar).

  5 ft above the float collar (over stop collar).

  Two centralizers for the following 3 joints then one centralizer per joint upto previous casing shoe.

  One positive centralizer every 3 joints for the remaining cased hole.

- Run 18 ⅝" casing, fill casing every three joints, check for losses or flow by using trip sheet, physical check, geolograph chart and weight indicator.
- Use Auto-fill Circulating head to fill or circulate the casing while running in hole; this requires less filling/circulating time and thus reducing the opportunity for differential sticking.
- Keep all pipe movement smooth and steady to avoid pressure surging and or differential sticking. Check returns to monitor any mud losses.
- If casing held up, circulate and reciprocate casing for enough time to clean hole.
- In case of pump and plug cementing method, make up cement head with plugs pre-loaded. Wash last one or two joints (dependant upon fill check trip).
- Land casing as per item no. 9.

8. Cementing 18 ⅝" Casing

Cementing 18 ⅝'' casing will be carried out by one of the following methods:

1) Inner string cementing method, or

2) Plug and Bump method

8.1 Inner String Cementing Method

- Run the proper cement stinger on 5" drill pipe (fit one drill pipe centralizer 10 ft above the stinger).
- Make up circulating head with 2" valve to the last DP joint, and test cement lines against valve to 1500 psi.

- Break circulation on top of F.C. Stab into float collar and set down 3,000 lbs of DP string weight. Continue to circulate, increasing rate to 400 GPM. Check that no returns are coming from the DP/casing annulus and continue to observe for this throughout the cement job.

- Pump 300 Bbls Low Viscous Mud followed by 40 Bbls of location or fresh water and 30 Bbls of Mix water.

- Mix and pump cement as per ADCO Lab formulations. Use 85 PCF cement slurry for lead and 118 PCF for tail slurry with 50 % volume excess in open hole.

- Pump 300 Sxs of cement for tail and the remaining volume is the lead light weight cement.

- Continue pumping lead cement until cement returns to surface; then pump tail cement (offset wells and status of the hole can give you good estimation of the cement volume needed).

- When the job is completed, displace the surface lines (approx. 2 Bbls) with mud and bleed off pressure. POH quickly washing inside drill pipe with water hose (consider pumping ID wiper to clean inside DP).

8.2 Plug and Bump Method

- When casing reaches bottom, make up cementing head with pre-loaded cement plugs.

- Pressure test cement unit and lines to 3000 psi for 10 min.

- Circulate at 4 to 6 BPM to break gelled up mud reciprocating casing gently and continuously. Then when drag up and down stabilizes, increase circulation rate gradually to 15 - 20 BPM until shale shakers are clean.

- Ensure that mud wt. in = mud wt. out before pumping cement.

- Pump the following spacers ahead of cement at 12 BPM: 300 bbls Low Viscous Mud followed by 40 bbls location water and 30 bbls Mix fluid.

- Drop the bottom plug (only the correct number / type of plugs to be loaded).

- Mix and pump 85 pcf lead slurry at 7- 8 BPM.

- Mix and pump class G cement 118 pcf (cement volume calculated based on 50% excess in OH and 10 % excess in cased hole).

- Drop upper plug, then displace cement starting by 10 bbls Location water and complete displacement with mud at 15 - 20 BPM.

- If any losses occurred prior to or while cement job reduce displacement rate to 10 BPM.

- Reduce displacement rate to 2 BPM 20 bbls before bump plug down with 1500 psi for 5 minutes.

- Release pressures and check for flow.

- In case of float equipment not holding, keep the cementing head valve closed till cement sets.

- Perform top job immediately if no cement returns to surface or if cement received at surface then level dropped back.

- Record total losses during cement job.

8.3 18 ⅝" Casing Top Job

If the cement slurry did not return to surface in the primary cement job, or if the cement reached surface but dropped again to a level which can not be anticipated exactly, conduct top job as follows:

8.3.1 Casing Landed on Heavy Duty Clamp (18 ⅝"x30'' Casing Annulus is Accessible)

Monitor annulus carefully during primary cementing to define if it is full of fluid or not (i.e. drilling fluid, water . . .)

- Severe loss, cement did not return to surface, annulus above top of cement is full of drilling fluid.
  - Before setting heavy duty clamp, run two Macaroni pipe strings at different sides of 18 ⅝"x30" annulus to top of cement, or to a maximum depth of 200 ft.
  - Mix and pump 118 pcf cement slurry through the Macaroni pipe until annulus is filled with cement.
  - If the cement slurry reached to the surface then dropped back, perform the cement top job using the procedure below.

- Cement returned to surface, then dropped back (annulus above cement column is empty)
  - Wait on cement 6-8 hours.
  - Lower 2” pipe few feet down the annulus.
  - Wait long enough for cement to settle down and top up the cement column to surface by pumping additional cement down the annulus.

8.3.2 Casing Landed on Casing Head (18 ⅝”x30’’ Casing Annulus is NOT Accessible)

- Severe loss, cement did not return to surface, annulus above top of cement is full of fluid.
  - Connect cementing line to on side of the Casing Head outlet
  - Pump 118 pcf cement slurry down the annulus to displace the fluid into the lost circulation zone and to push cement column down to the base of the lost circulation zone.
  - Watch pressure carefully; ensure pump pressure do not exceeds 400 psi surface pressure to avoid casing collapse.
  - Fill cement slurry down annulus at lowest rate keeping other Casing Head side outlet open to the atmosphere. Watch for any returns from the 2nd outlet.
- Cement returned to surface then dropped back (annulus above top of cement is empty).
  - Wait on cement 6-8 hours.
  - Fill cement slurry down annulus at lowest rate keeping other casing head side outlet open to the atmosphere. Watch for any returns from the 2nd outlet.

9. Landing Casing / Installing Wellhead

Landing 18 ⅝” casing depends on the cementing method, either stab-in or Plug and Bump and depends also on the wellhead equipment:

- Conventional Heavy Duty Clamp

  <u>Or</u>

- Special “Casing Head” that can provide hydraulic sealing between 30’’ conductor pipe and 18 ⅝’’ casing.

Note:

This landing method can only be used if four (4) or more 30” conductor pipes are run and completely cemented to surface; otherwise heavy duty clamp should be used.

9.1 Landing 18 ⅝” casing for Stab-in Cementing Method

9.1.1 Landing on a Standard Heavy Duty Clamp

- After drilling 26” phase to TD, lay down riser or diverter.
- Run 18 ⅝” casing to bottom, space out to have top casing collar at 2 ft above bottom of cellar.
- Install Heavy Duty Clamp and land casing (Casing weight should be slacked-off on the casing body and not on the casing collar) Figure 2- 17.
- Unscrew and lay down landing joint.
- Run stinger assembly.
- Proceed to cementing.
- Wait on cement 6 hrs.
- Lay down 18 ⅝” landing joint.

Note: Remove the Heavy Duty Clamp prior to start the next drilling phase or prior to handover the well to Production Operations Division.

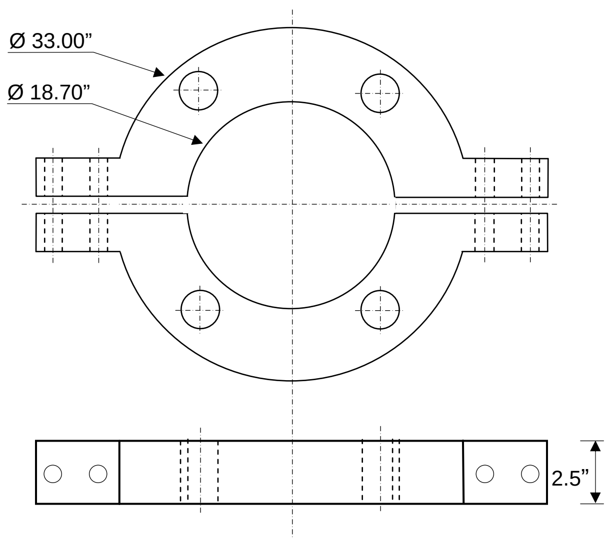


Figure 2- 17:- Heavy Duty Clamp for Landing 18 ⅝” Casing

9.1.2 Landing 18 ⅝” Casing on Special “Casing Head”

- Set last casing joint on slips, install safety clamp and remove casing collar.
- Make up the Casing head to the last 18 ⅝” casing joint.
- Make up the Handling Tool to the CH assembly.
- Pick up the casing string, Orientate CH so that the outlets are facing to the direction desired. Lower CH slowly and carefully through the rotary table. Land the CH on the load shoulder of the 30” landing ring. Figure 2-18 and Figure 2-19.
- Retrieve the Handling tool.
- Run stinger assembly.
- Cement the 18 ⅝" casing.

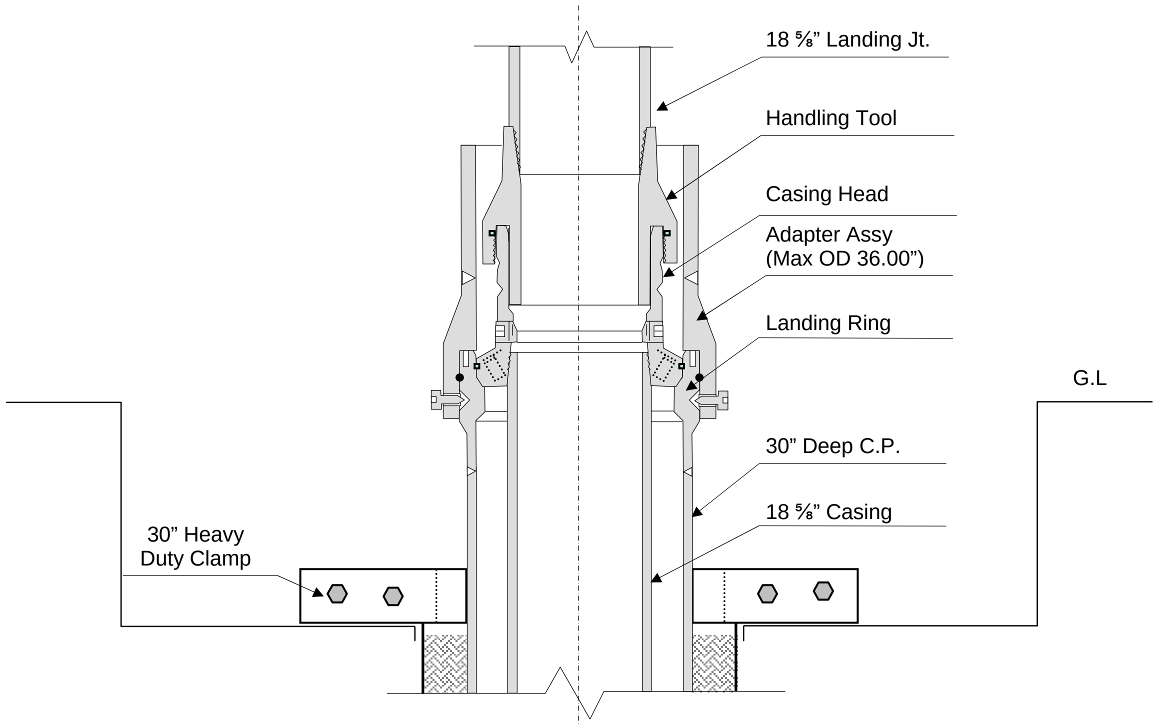


Figure 2-18: 18 ⅝" Casing Landed on 30" landing ring

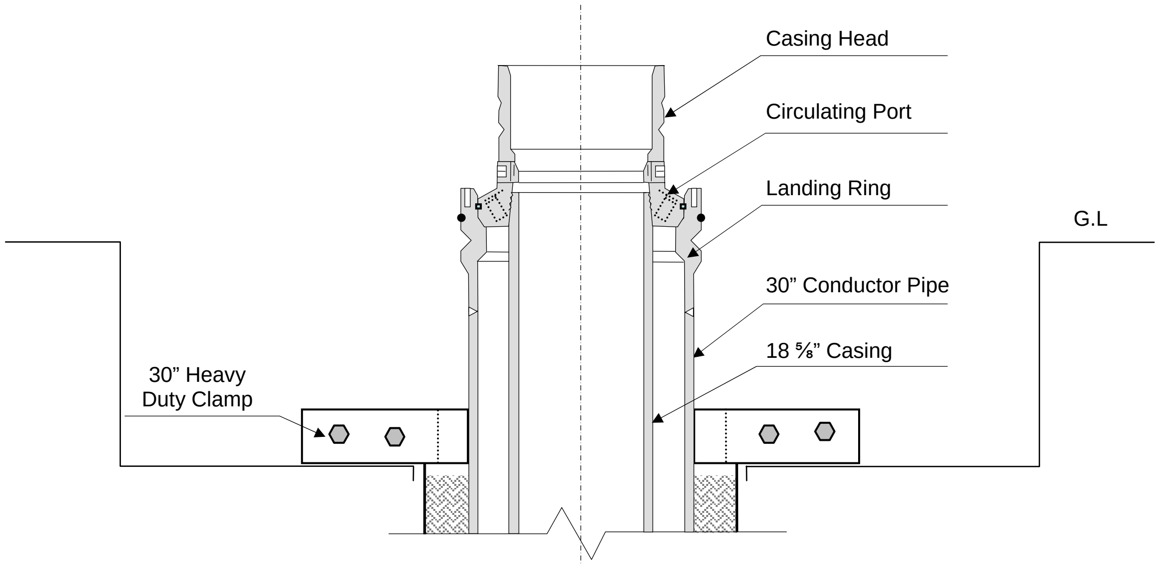


Figure 2-19: Mud Riser or Diverter removed after landing 18 ⅝" Csg

9.2 Landing 18 ⅝” casing for Plug and Bump cementing method

9.2.1 Landing 18 ⅝’’Casing on Heavy Duty Clamp

- After drilling 26“ hole, run 18 ⅝” casing, make up last joint (landing joint) and set on slips.
- Install the cementing head with plugs pre-loaded.
- Adjust last casing collar position for installing casing clamp. At this point, the casing shoe is at 5 – 10 ft off-bottom and the first casing collar is at 2 ft above cellar floor, check casing string weight.
- Proceed to cementing 18 ⅝” casing.
- If water flow is expected, WOC for 6 hrs.
- Raise riser/diverter and hang in substructure.
- Cut 30’’ conductor to 1 ft above cellar floor level.
- Install 18 ⅝” Heavy Duty clamp and slack off casing weight.
- Lay down 18 ⅝” landing joint.
- Nipple down riser/diverter.
- Carry out top job if needed.

Note: Remove the Heavy Duty Clamp prior to start the next drilling phase or prior to handover the well to Production Operations Division.

9.2.2 Landing 18 ⅝” Casing on “Casing Head”

- Run 18 ⅝” casing, make up last joint, set on slips, secure with safety clamp and remove collar.
- Make up Casing Head assembly (with landing joint) to last casing joint.
- Run in hole slowly and land casing head on 30” landing ring load shoulder.
- Proceed to cementing 18 ⅝” casing.
- Lay down landing joint.
- Nipple down riser/diverter.

10. Potential Operational Hazards

Table 2-10: Drilling Hazards in Drilling 26" Hole

Potential Hazard	How to mitigate
Severe water flow or loss	• **Understanding the Miocene and Dammam formation:** 0 Miocene Clastics consisting mainly of limestone and Marls. This section is unconsolidated and can dump sand and stones into the well bore around drill string. This occurs when fluid level drops due to losses while drilling Dammam formation. • **Drill surface hole cautiously:** 0 Review offset wells prior to spudding the well 0 In case of sudden losses, try to continue drilling with controlled GPM and ROP. circulate at least bottom up prior to POH. 0 To avoid losses into Dammam, circulate and clean hole at 50' above top Dammam and displace with fresh mud. 0 Be prepared to fill hole down annulus at maximum possible pumping rate. 0 Drill with the maximum possible GPM (1000 GPM minimum), watch shale shaker carefully and ensure hole clean.
Stuck drill string Miocene heaving following sudden and severe losses into top Dammam	• Maintain mud weight as close as possible to water by dilution and spotting fresh mud. • Close monitoring of losses while drilling top hole. • Don't apply more than 30 klbs overpull, if needed, back reaming and pumping out is the best solution. • Clear instructions to Driller regarding the first action in case of stuck pipe.
• Stuck casing, drilling crooked hole, unstabilized BHA • Losses followed by sand caving • Tight hole	• Stick to the BHA specified in the drilling program. • Avoid creating ledges by easing bit in harder formation and reaming transition between formations. • Avoid thick mud cake by controlling fluid loss and solids. • Take Totco survey at bottom. • Work out tight hole spots.
Eliminate drilling surprises: Losses, stuck Drill string, stuck casing.	• Watch losses while drilling and running casing. Massive dilution of water will be required to maintain mud weight. Use viscous gel sweeps on connections, if required, to clean the hole. • Agree with Driller and Rig Manager the initial action to be taken for each problem that is likely. • Refer to lessons learnt, achievements and difficulties prior to drill the phase.

11. Blowout Prevention

Next drilling phase (17 ½'') will be drilled to Dammam, Rus or Fiqa. Well control / monitoring equipment i.e. mud riser, diverter or annular preventer will be selected based on the following criteria:

Table 2-11: BOP System Required for Drilling 17 ½" Hole

13 ⅜" Setting Depth	18 ⅝'' Mud Riser	21 ¼" Diverter	21 ¼" Annular Preventer
13 ⅜'' casing set at Dam.	Yes	No	No
13 ⅜'' casing set at Rus	Yes	Only if flow was experienced from Dammam in offset well	No
13 ⅜'' casing set at Fiqa	No	No	Yes

11.1 Mud Riser 18 ⅝"

Mud riser is welded on the proper size and type of adapter assembly, lowered through rotary table to land on the casing head and be secured with hold down screws.

11.2 21 ¼" Diverter

- Make up the following assembly on rig floor
    - o 21 ¼" Mud Cross, with 2 x 4" flanged outlets, one is to be used as vent line and the other one is to be connected to the kill line. Equipped with one 3" manual valve and one 4" HCR valve.
    - o Make up the 21.26" adapter assembly
    - o Running tool
- Lower the assembly, land on casing head and secure using the Hold down screws.
- Nipple up 21 ¼" - 500 psi diverter. Figure 2- 20
- Install bell nipple 21 ¼".
- Connect vent line, kill line and valves.
- Function test and pressure test to 200 psi is required. Valves are tested off-line prior to cementing.

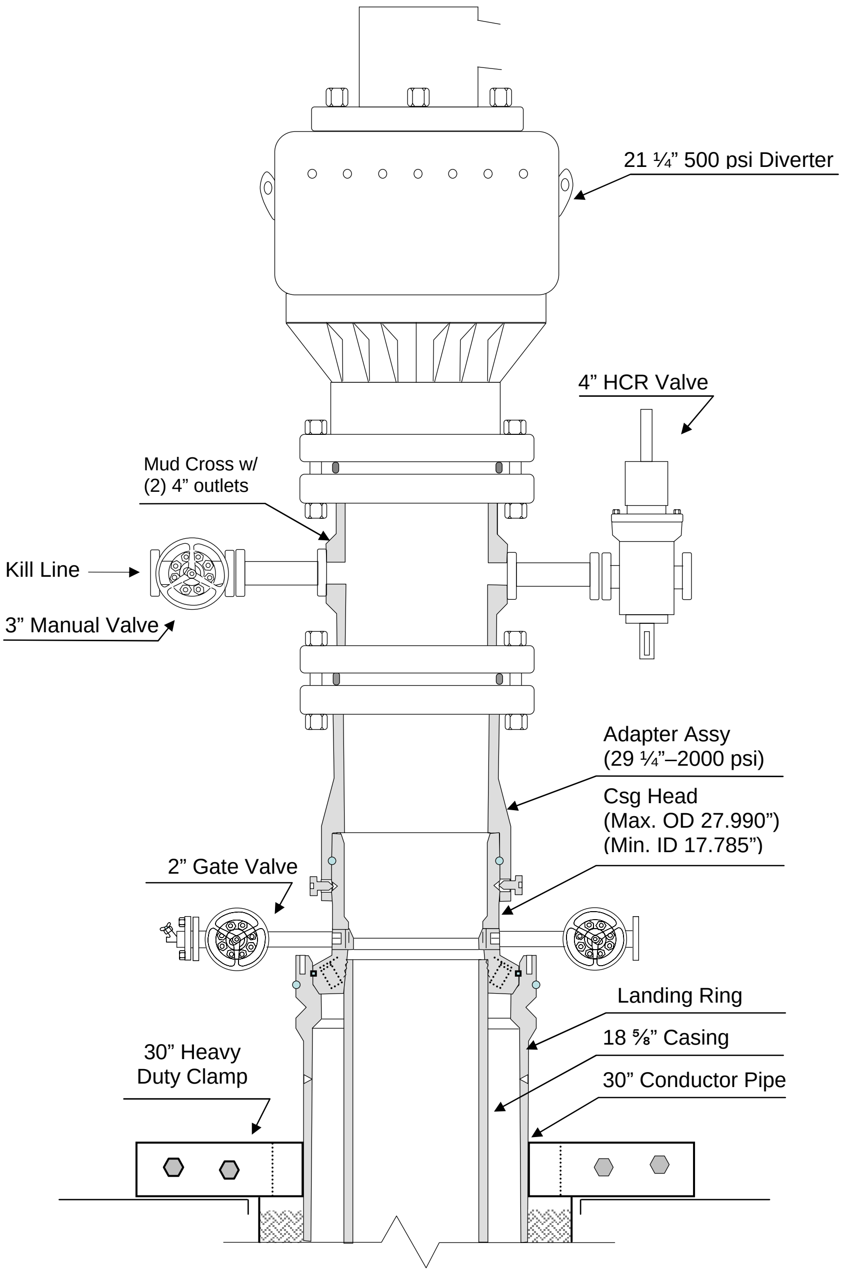


Figure 2- 20: Diverter Stack for Drilling 17.1/2” Hole

11.3 Annular Preventer

- Use the above procedures to nipple up 21 ¼” x 2000 psi Annular Preventer and 21 ¼” and Mud Cross, with 2x4” flanged outlets for choke line and kill line.

- Mud cross is equipped with two manual valve (3” and 4”) and two HCR valve (3” and 4”). Figure 2-21.

- Function test annular preventer and HCR valves

- Pressure test BOP’s stack as per Chapter-3 “Well Control” of this volume

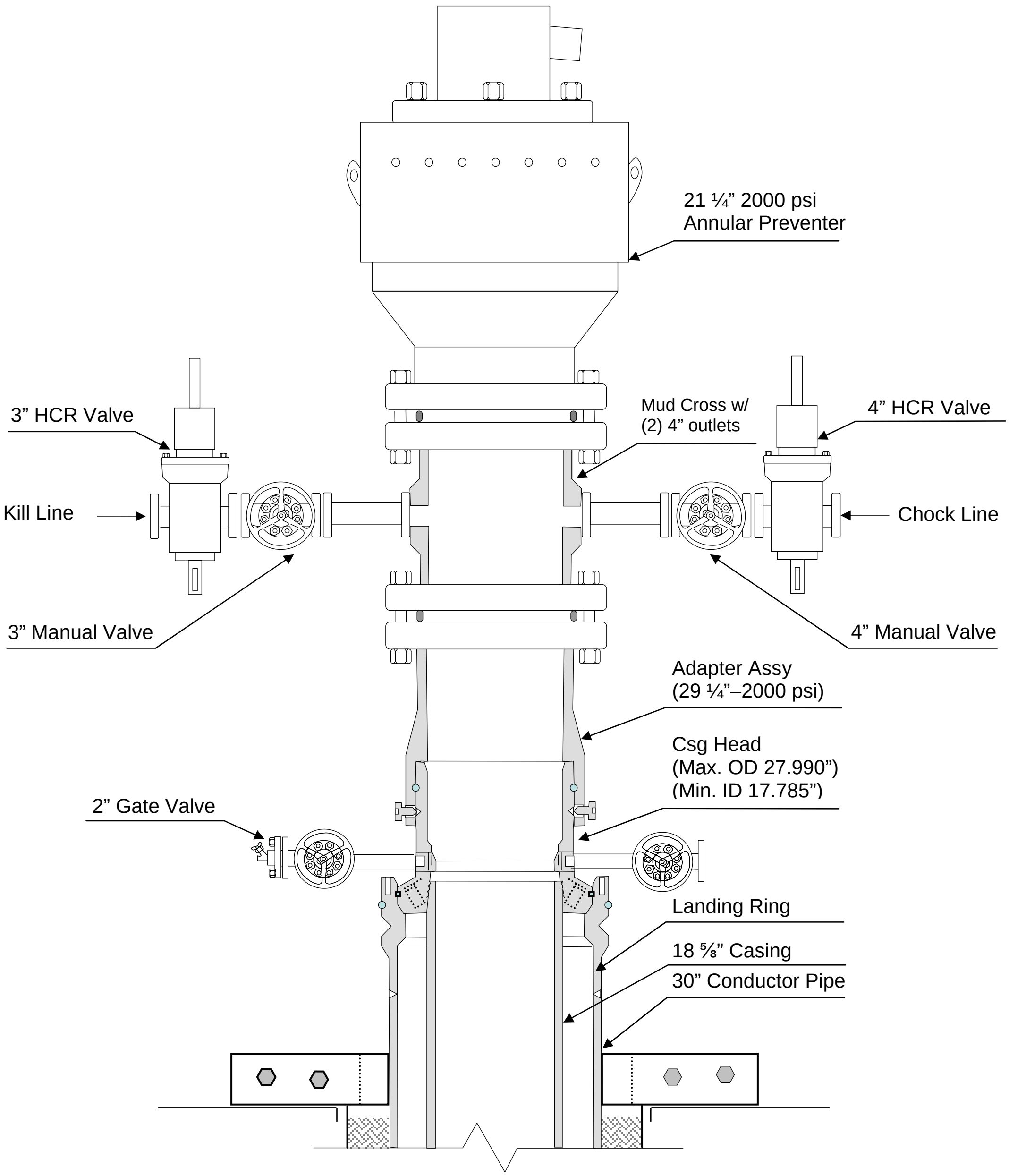


Figure 2-21: BOP Stack for Drilling 17.1/2” Hole

12. Equipment Required

The following equipment is required for the 26” phase:

12.1 Tubular and casing equipment

Table 2-12: 18 ⅝” Casing and Accessories

S.N.	Description	Grade	Wt lb/ft	Thread	MESC No.	Store
1	Casing (R-3)	K-55	87.5	BTC	04.20.03.605.9	2
2	Stab-in Collar	K-55	87.5	BTC	05.14.26.032.9	2
3	Stab-in Shoe	K-55	87.5	BTC	05.14.17.044.9	2
4	O.H. Centraliser	-	-	-	05.17.25.912.9	2
5	Stop Collar	-	-	-	05.17.55.148.1	2
6	Casing dope	-	-	-	87.47.25.07.09	2
7	Thread compound	-	-	-	87.42.47.24.09	2

Note:

- For Plug and Bump cementing method, use standard float collar mesc No. 0514260309 (this item includes the 2 cement plugs as one set).
- Same stab-in shoe is used for both cementing methods.
- The 3 top 18.5/8” joints mast be corrosion coated.

Dimensions, mechanical properties and make up torque of the 18 ⅝’’ casing:

Table 2-13: 18 ⅝” Casing Properties

Option	18 ⅝” Casing
Body OD (in)	18 ⅝
Grade	K-55
Weight with collar (lb/ft)	87.5
Connection	Buttress
Min. ID (in)	17.755
Drift diameter (in)	17.567
OD of coupling (in)	19.625
Capacity (bbls/ft)	0.3062
Body yield strength (klbs)	1367
Coupling yield strength BTC (klbs)	1427
Collapse pressure (psi)	630
Burst pressure (psi)	2250
Make up torque optimum	Triangle level

12.2 Wellhead

- Casing Head Assembly
- Nipple, Type N-5
- Ball valve, 2” 2K WP
- Bull Plug, 2” LP x ½“ LP
- Needle Valve
- Bull Plug, 2” LP
- Flush Plug

13. Waste Management

13.1 General

<table>
<tr><th>Hole Size</th><th>Mud Salinity</th><th colspan="2">Rental Equipment</th><th>Mud Handling</th><th>Cuttings Handling</th></tr>
<tr><td rowspan="2">26"</td><td rowspan="2">Water Base Mud</td><td>Tanks</td><td>4</td><td rowspan="2">**NO DUMPING**
Excess mud to be transported to injection disposal well.</td><td rowspan="2">Cuttings to be piled on location and to be used to bund the location.</td></tr>
<tr><td>Centrifuge</td><td>1</td></tr>
</table>

- No waste pits should be dug, use instead a 300 Bbls tank to collect waste mud and then transfer to the waste disposal site.

- Environment inspection checklist to be filled in at least weekly and sent to office.

- Ensure sewage treatment unit discharge analysis is meeting ADNOC regulations.

17 ½” HOLE FOR 13 ⅜” CASING

1. Purpose

17 ½’’ hole in ADCO is drilled to run 13 ⅜’’ casing as an intermediate casing string set at top Dammam minimum or deep to cover UER and Simsima and set shoe into top Fiqa.

13 ⅜’’ casing is typically run to:

- Case-off part of Miocene formation prior to drilling Dammam formation.

  Or

- Case-off Dammam formation prior to drilling UER and Simsima formation.

  Or

- Case-off UER and Simsima prior to drilling Nahr Umr Shale and pay zones.

2. Applications

13 ⅜” casing setting depths depends on the overall well casing design and well type, see table bellow.

Table 2-14: 13 ⅜” Casing Setting Formation

Well Type	Casing Setting Formation		
	Dammam	Rus	Fiqa
Gas producer/injector and WAG	X	X	√
Oil producer	√	√	√
Water injector	√	√	X
Water supply	√	√	X

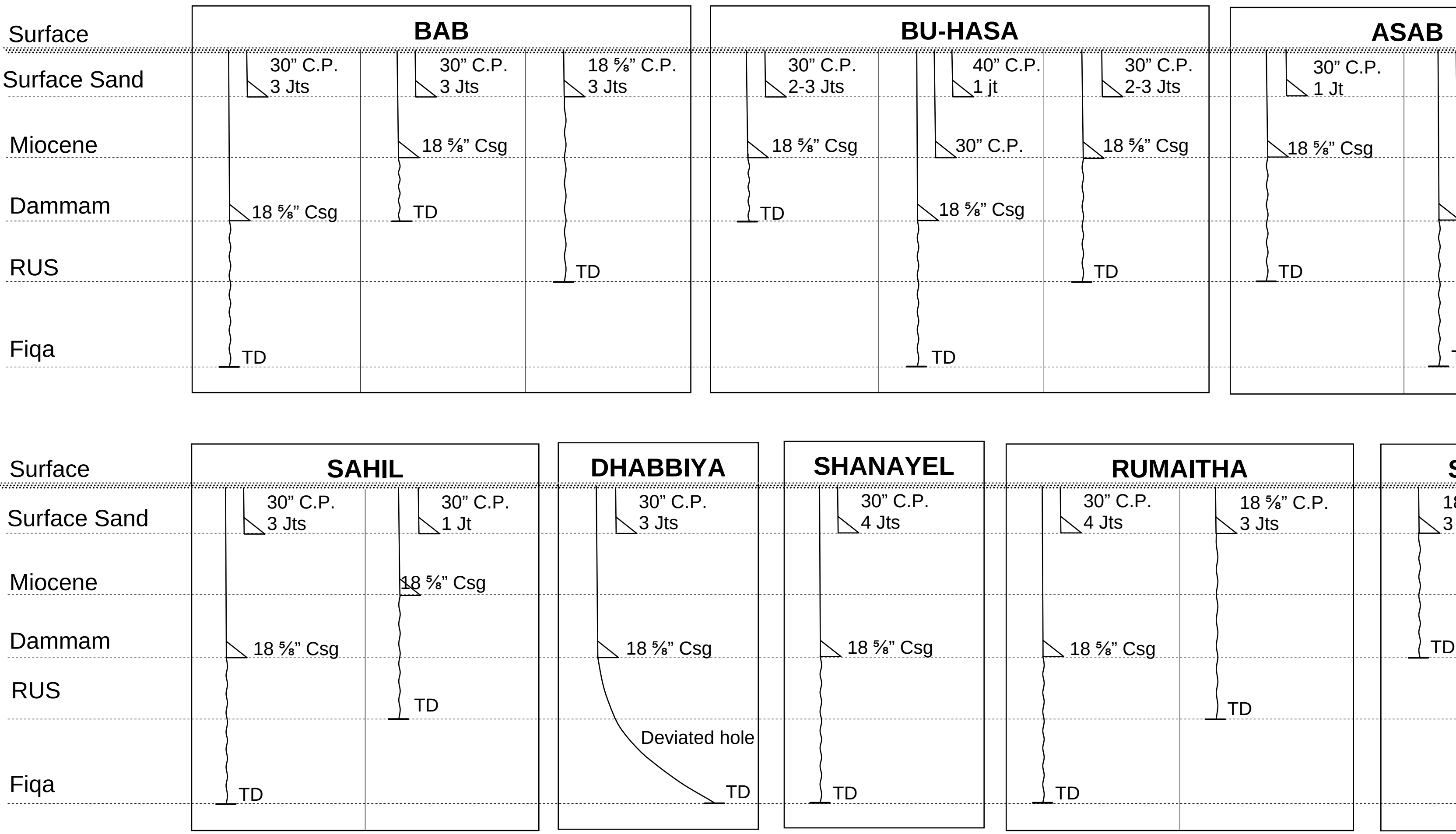


Figure 2- 22: : – ADCO’s Typical 17 ½” Phase

3. Preparations and Off- Line Operations

3.1 During Drilling 26'' Hole and Cementing 18 ⅝'' Casing

- Prepare 13 ⅝'' CHH made up to a casing nipple of 1 ft length (pin x pin).

- Prepare for running 13 ⅝'' CHH through rotary table. Protect lock down screws and valves from damage.

- Prepare to replace rotary table with false or split type, as applicable, to allow passage of CHH and running tool through rotary. The false RT should be of enough set back capacity to withstand casing load.

- Check and measure, 17 ½" BHA components dimension.

- Make up 17 ½" BHA.

3.2 During Drilling 17 ½'' Hole

- While circulating hole clean at 17 ½" hole TD, check 13 ⅜" casing handling equipment (i.e. elevator, single joint elevator, slips, casing bowl, casing tongs, casing thread protectors, Quick latch, Auto filling tool, cementing plugs, cementing head. Make it ready on rig floor.

- Make up as per program float shoe and float collar on 13 ⅜" casing joints on pipe rack.

- Work on casing stub, wellhead and BOP to prepare for next operations as applicable.

3.3 During cementing 17 ½'' casing

- Check and measure, 12 ¼" BHA components.

- Plan top cement job as to meet the requirement of having good cement to surface.

- Position in place and test choke manifold and flare lines.

4. Drilling 17 ½" Hole

17 ½" hole is drilled through Mud riser Figure 2-23, Diverter Figure 2-23 or Annular Preventer Figure 2-25 as follows:

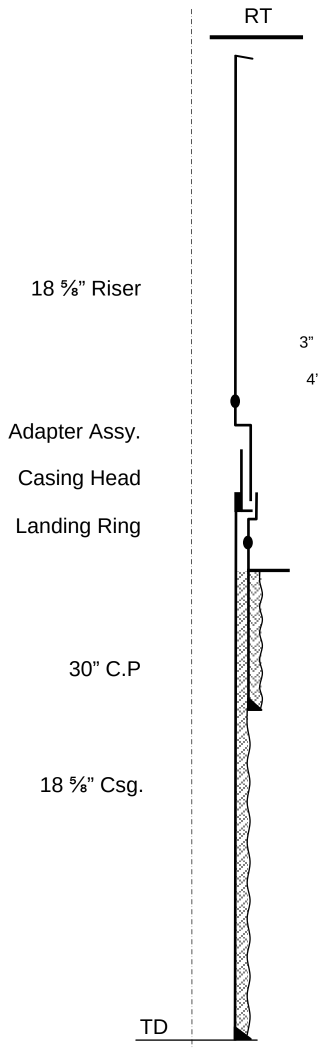


Figure 2- 23: Drilling 17 ½” Hole through 18 ⅝” Riser

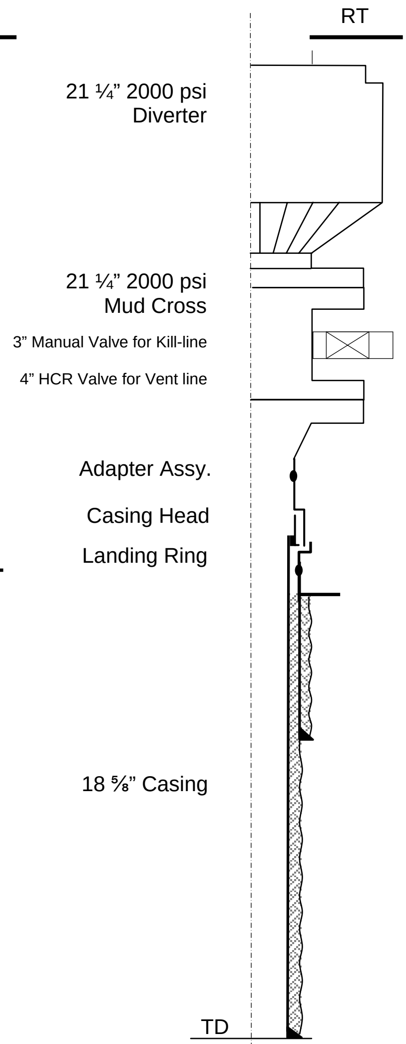


Figure 2-24: Drilling 17 ½” Hole through 21 ¼”x2000 psi Diverter

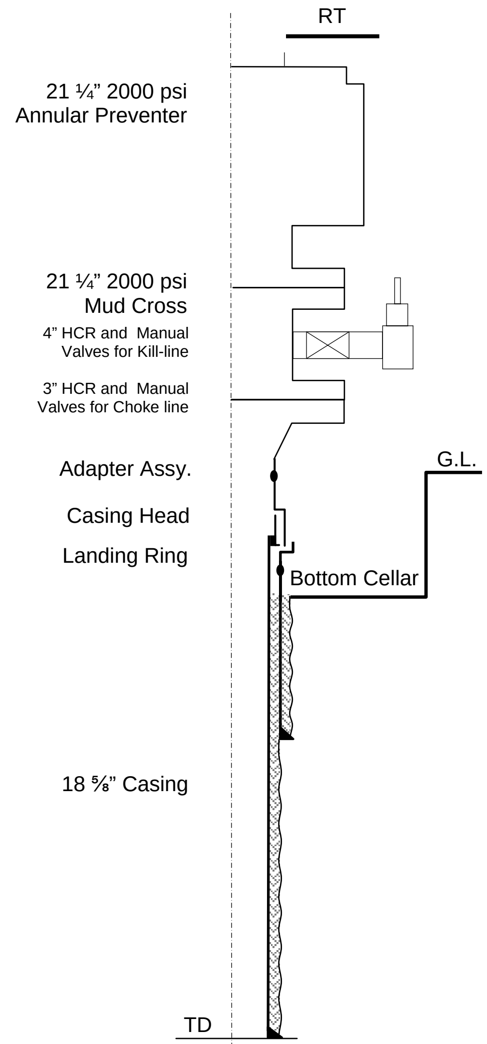


Figure 2-25: Drilling 17 ½” Hole through 21 ¼”x2000 psi Annular preventer

4.1 Recommended Bottom Hole Assemblies for Drilling 17 ½" Hole

Table 2- 15 Recommended BHA for Drilling 17 ½" Hole

Option 1 Rotary drilling			Option 2 Motor drilling		
Size	**Description**	**No.**	**Size**	**Description**	**No.**
17.5"	Bit	1	17.5"	Bit	1
10.5"	Shock sub	1	9.5"	Motor w/17.5" sleeve stab	1
9.75"	Drill collar	1	17.5"	Roller reamer	1
17.5"	String stabilizer	1		MWD	1
9.75"	Drill collar	1	17.5"	Roller reamer	2
17.5"	String stabilizer	1	9.75"	Drill collar	7
9.75"	Drill collar	2	9.5"	Drilling jar	1
9.75"	Cross over	1	9.75"	Drill collar	1
8.25"	Drill collar	10	9.75"	Cross over	1
8"	Drilling Jar	1	8.25"	Drill collar	12
8.25"	Drill collar	2	8.25"	Cross over	1
8.25"	Cross over	1	5	HWDP	15
5"	HWDP	9			

4.2 Drilling Guidelines

- Clean out 18 ⅝" casing, drill floats.
- Drills first 100' below 18 ⅝" shoe with reduced parameters (WOB, RPM and flow rate) until the stabilizers/roller reamers are below 18 ⅝" shoe.
- Avoid washing out the unconsolidated formation around 18 ⅝" casing shoe.
- Kick off 17 ½" hole or continue drilling vertical to TD as per program.
- Total depth should be adjusted to suit casing tally plus 5 to10 ft sump.
- Ream every kelly if the hole condition dictates, otherwise drill without reaming.
- Wiper trip should not be planned unless hole condition dictates.
- Circulate hole clean. Pump sweeps of L.V.M followed by H.V.M while drilling the last connection to casing point and circulate hole clean.
- Optimize drilling parameters to obtain the maximum ROP and good hole condition.
- Circulate hole clean at top Dammam formation to unload hole from cuttings to avoid losses into Dammam.

4.3 Drilling 17 ½” Using Aerated Mud

- Refer to Chapter-2 “Special Drilling Operations” in volume-2 for complete details.
- Aerated drilling technique in ADCO is used to drill UER and Simsima formations.
- Install rotating head on top of BOP to ensure sealing around drill string while drilling or tripping.
- A ported float must be installed above motor to prevent back flow.
- Losses and flow are anticipated while drilling Dammam and UER formations. Air injection results in lower hydrostatic hence helping control losses.
- Pumping of maximum GPM mud (above 850 gpm) should be maintained whenever possible, however, at deeper depths, surface pressure might exceed the air compression equipment capability. In this case mud flow rate should be reduced to have the surface pressure within the air package limitations.
- Increasing the penetration rate causes minor increases in the air volume requirements.
- As depth increases the air injection rate should be increased to accomplish the same hydrostatic pressure at the bottom by decreasing the surface gradient.
- If water influx is detected, reduce air injection rate, keep drilling. Be aware of sour aquifers if flow is encountered.
- At 17 ½” hole TD and prior to trip out of the hole, circulate hole clean while injecting air then stop air injection and spot 400 bbls mud at bottom, keep string full with mud, observe blooie line, remove rotating head insert after pulling at least 10 stands.

5. Drilling Fluid

Water Base Low Solid Non Dispersed Mud (LSND) is normally used to drill this section, for more details refer to Chapter-5 “Mud Guidelines” of this volume.

Table 2-16: Aerated Drilling Mud Properties

Density, pcf	58 - 60 or as hole conditions dictates
Viscosity, sec/qt	40 – 50
YP, #/100 ft^2	16 – 20
PV, cps	ALAP / 7 – 10
10 sec Gel , #/100 ft^2	3 – 6
10 min Gel , #/100 ft^2	8 – 12
API FL, cc/30 min.	N/C to 15 – 20 prior to running CSG

Drill Solids Content, %	< 6 (max.) LGS
Sand , % by Volume	Traces – 0.5 (Max.)
pH	11.0 – 12.5
MBT , ppb	20 - 25

Corrosion Inhibitor (Sodium Silicate)

- Sodium Silicate is to be as corrosion inhibitor.
- Pump high viscous high concentrate sodium silicate pill periodically while drilling with aerated Mud.

6. Drilling Optimization

6.1 Bit Selection

- Depending on the hole scenario, and planned TD, various bit options are used.
- For TD in top Dammam, a steel tooth bit is sufficient, IADC 1.1.5. For longer runs, insert bits are used.
- For TD in top of Rus, insert bits IADC code 4.1.5 or 4.2.5 are commonly used.
- When the planned TD is deeper (into Fiqa formation), and it is planned to drill through the Rus anhydrite, a harder cutting structure is required, for example IADC 4.4.5 type insert bits.
- Directional wells normally TD in Fiqa, and require an IADC 4.4.5 or similar type bit.
- The main challenge to cutting structure damage is the Rus anhydrite. The Rus anhydrite is relatively hard (compared to other formations encountered in 17 ½”), and care with drilling parameters needs to be exercised (more details in the section Drilling Hazards).
- PDC runs have been tested; however the economics need to be carefully evaluated, due to the high expense of 17 ½” PDC bits.
- Select bits with features that help reducing balling problem.

6.2 Hydraulics and Nozzles Selection

- Hydraulics and nozzles selection shall be completed for every run.
- Well plan (LandMark application) to be used for hydraulics calculations.
- A pressure loss of (100-150) psi to be considered for surface lines and stand pipe.

- Due to the relatively high ROPs achievable, and the large hole size, good hole cleaning is critical, hence high flow rate has to be the priority (more under hole cleaning). The bit therefore needs to be nozzled accordingly.

- Choose appropriately large pump liners.

- Bit balling is a risk through the Dammam Basal shale, and Umm Er Radhuma Basal shale. In order to reduce this risk, it is recommended, to try and achieve an H.S.I. (hydraulic power per square inch) of at least 2. Being able to achieve this, while maintaining the required high flow rates, will depend on rig pressure limitations.

- Center nozzling is recommended in 17 ½" and greater, to help clean the centre of the bit.

- In addition, asymmetrical nozzling can further enhance bit face cleaning by promoting cross flow.

- Oriented nozzling designs are suited for reducing bit cutting structure balling.

6.3 Motor

- 9 ½" (or similar e.g. 9 ⅝"), medium speed motors are standard.

- Larger sized motors can be used, but careful consideration needs to be given to flow rate capability. The required RPM needs to be generated from flow rates in the region of 850 to 1000 gpm, without incurring undue motor differential pressure loss.

- For vertical hole, and performance motor drilling, it is recommended to remove bent housing, and replace with straight tube. This has been shown to reduce the risk of motor twist off, due to the heavy parameters used in this section, in order to maximize ROP.

6.4 Hole Cleaning

- For vertical hole, a minimum of 850 gpm is recommended, although closer to 1000 gpm is normally used, due to high ROP achievable.

- For deviated hole, in excess of 1000 gpm is recommended (especially for inclination > 40 degrees).

- The above recommendations are very generic, and each application should be analysed accordingly. Factors influencing hole cleaning include: flow rate, annular cross-sectional area (hence drill pipe OD), mud rheology and mud weight, cuttings size, inclination, drill pipe rotational speed, length of sliding intervals (zero pipe rotation), drill pipe eccentricity and ROP.

- In addition, flush the hole with 50 - 100 bbls high viscous pill, viscosity of 120-150 sec/qt periodically.

- Carefully monitor pick-up, slack-off, and off-bottom torque readings. Trend anomalies could indicate pack-off risk.

- Reduce bit cutting structure balling by adding lime to mud.

- Monitor shale shakers (shakers clean).

- If losses problems exist, ECD needs to be carefully controlled.

6.5 Drilling Parameters

- Avoid operating parameters that lead to drill string vibrations. Use a rotary speed that is high enough to give smooth rotation of the drill string, but not so high that axial and/or lateral drill string vibrations or bit whirl occur.

- Keep the applied weight on bit smooth once it has been optimized. Feed weight continuously to the bit using the Driller's electric brake if available and avoid "slack-off / drill-off" - this can contribute to damaging BHA due to torsional vibrations.

- Reduce the applied weight on bit, pump rate and/or rotary speed as necessary to ensure that the penetration rate does not exceed the maximum allowable ECD.

- Operate at the weight on bit, pump rate and rotary speed (if needed) that gave the highest penetration rate in the drill-off tests, unless significant losses problem is expected.

- Expect ROP reduction in Rus.

7. Running 13 ⅜" Casing

- Make up float shoe to the 1st joint of 13 ⅜" casing joint and float collar to the Box of 2nd joint.

- Install two joints between shoe and float collar.

- Use thread locking compound to make up float collar and float shoe and the two joints between.

- If casing grade is K-55 or lower, tag weld float shoe and float shoe with the casing joints between.

  Note:

  o Float shoe and float collar are equipped with spring type valve, and dispatched to the location with valves locked open with a plastic retainer (allows two ways flow passage.) The valves must be activated prior to running in hole by removing the plastic retainer by hand. However the valves can be activated by breaking circulation at high rate.

    - Centralization programme should be checked in high angle wells to ensure having 80% standoff.

- Install open hole centralizers as follows:
    - One centralizer. 5 ft above shoe (over stop collar).
    - One centralizer. 25 ft above shoe (over stop collar).
    - Two centralizers. Every joint for the next 4 joints (over stop collar).
    - One centralizer. every 3 joints (over stop collar) for the remaining open hole
    - One positive centralizer above 18 ⅝" casing shoe if applicable.
    - One positive centralizer per joint for the remaining cased hole.
    - One positive centralizer 10 ft below cellar and one centralizer 25 ft below first joint casing.

- Run 13 ⅜" casing in hole, filling every joint for the first three joints (flow check floats) and then fill casing every 3 joints. Check for losses or flow by using trip sheet, physical check, and/or steady increase in string weight on weight indicator and geolograph chart. Ensure floats are functioning properly.

- Keep all pipe movement smooth and steady to avoid pressure surging and or differential sticking.

- If casing held up, circulate and reciprocate casing for enough time to clean hole.

8. Landing 13 ⅜" Casing

13 ⅜" casing string is landed on conventional heavy duty clamp or on casing hanger mandrel; the procedures are also different based on whether the hole was drilled through mud riser or annular preventer/diverter.

8.1 Landing 13 ⅜" Casing on "Casing Hanger Mandrel"

Proceed as follows if casing is to be landed on "Mandrel Casing Hanger":

- After drilling 17 ½" hole, run 13 ⅜" casing. Make up last joint. Set on slips and remove collar.

- Make up Casing Hanger Mandrel assembly (with Landing Joint) to last casing joint.

- Run in hole slowly, land casing hanger Mandrel on 18 ⅝" Casing head load shoulder

- Proceed to cementing 13 ⅜" casing.

- Lay down landing joint
- Nipple down annular preventer / diverter, Figure 2-26.

Note:

If 17 ½" hole is drilled through 18 ⅝" riser, nipple down riser before running 13 ⅜" casing (mandrel casing hanger OD = 20.116" and 18 ⅝" casing ID = 17.755")

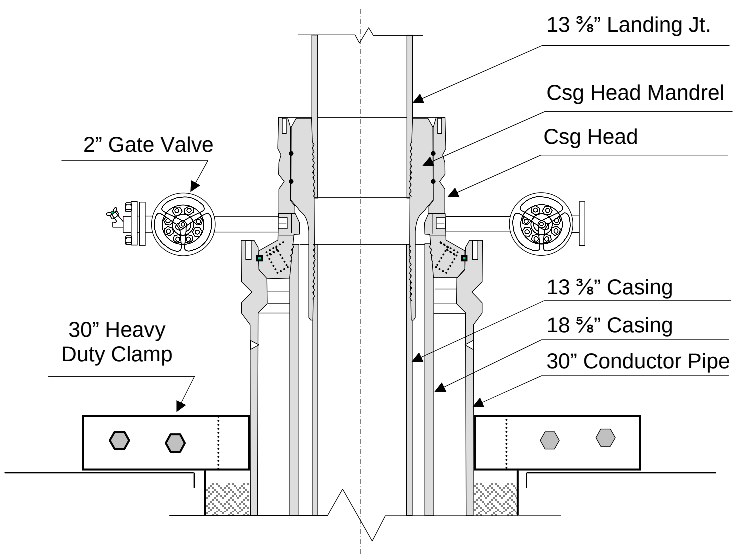


Figure 2-26: 13 ⅜" Casing landed on CH Mandrel

8.2 Landing 13 ⅜" Casing on Heavy Duty Clamp

- After drilling 17 ½" hole; run 13 ⅜" casing, make up last joint and set on slips
- Make up landing joint and cementing head on top with plugs preloaded. Run in hole and wash down to bottom.
- Adjust last casing collar position for installing casing clamp. At this point, the casing shoe is at 5 – 10 ft off-bottom and the first casing collar is at 1 ft above cellar floor. Confirm final CHH level position, check casing string weight.
- Proceed to cementing 13 ⅜" casing.
- Raise 18 ⅝" riser, annular preventer or diverter and hang in substructure, cut remaining 18 ⅝" casing.

- Install Heavy Duty Clamp, Figure 2-27 on 13 ⅜” casing and land on 18 ⅝” casing.
- Lay down 13 ⅜” landing joint.
- Continue nippling down riser, annular preventer or diverter.

Note: Remove the Heavy Duty Clamp prior to start the next drilling phase or prior to handover the well to Production Operations Division.

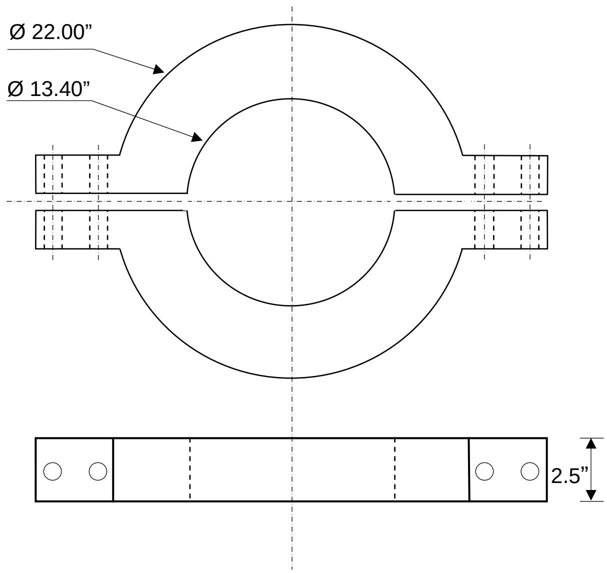


Figure 2-27: Heavy Duty Clamp for Landing 13 ⅜” Casing

8.3 Casing Landing Summary

- In case where casing hanger mandrel is to be used, land 13 ⅜” casing before cementing.
- In case where heavy duty clamp is to be used, land 13 ⅜” casing after cementing.

9. Cementing 13 ⅜” Casing

13 ⅜" casing will be cemented in one stage. The volume of cement is calculated based on 50% excess on open hole and 10% excess for casing volume. Tail slurry is 300 Sxs cement and the remaining volume will be lead cement.

- Test cement lines against valve on cementing head to 3000 psi for 10 min. Record the pressure on chart.

- Pump ahead of cement 400 Bbls of low viscosity mud followed by 30 Bbls location water and 40 Bbls of Mix.

- Mix and pump cement of recipes as per ADCO Lab formulation.

- Release top plug.

- Displace cement with the rig pumps at a minimum flow rate of 15 bpm. Pump the last 10 bbls of displacement volume of mix water to flush the lines. Maintain a careful check on returns and record any losses.

- In the event of losses cut back pump rate to 5 BPM.

- Slow down pump to 2 Bbls before bumping plug. In case of not bumping plug do not over-displace cement. Pump only theoretical displacement volume.

- Pump plug with 2000 psi and hold for 10 minutes. Release pressure and check if float is holding. If not, close cement head for 6 hours and repeat.

- In case Diverter is used (i.e. for wells of low elevation, where flow is a possibility), proceed as follows after completing the cement job.

- Wait on cement for 6 hours observing the well carefully
  - o If any flow is observed, check injectivity, bullhead cement to kill well. (Maximum 60% of 13 ⅜" casing collapse pressure). Flush kill line with water after pumping cement. Close kill line and wait on cement for 6 hrs from the time pumping cement stopped.
  - o If losses are indicated so that cement level in the 13 ⅜" x 18 ⅝" annulus is significantly dropped, fill annulus with cement.
  - o After ensuring well is safe and no flow is possible, proceed as per program.

9.1 13 ⅜" Cement Slurry Specifications

Table 2-17: 13 ⅜" Casing Cement Slurry Specifications

Casing Setting Formation	Spacer Ahead	Slurry Type	
		Lead Slurry	Tail Slurry
Dammam	• 30 Bbls Location Water • 40 Bbls Mix Water	Light weight cement slurry (84/86 PCF)	Class G cement slurry (118 PCF)
Rus	• 30 Bbls Location Water • 40 Bbls Mix Water	Light weight cement slurry (84/86 PCF)	Class G cement slurry (118 PCF)
Fiqa	• 30 Bbls Location Water • 40 Bbls Mix Water	Light weight cement slurry (75/80 PCF or 64/70 PCF)	Class G cement slurry (118 PCF)

9.2 13 ⅜" Casing Top Job

If the cement slurry did not return to surface in the primary cement job, proceed to conduct top job as follows:

9.2.1 13 ⅜" Casing Landed on Heavy Duty Clamp

Monitor annulus carefully during primary cementing and define if it is full of fluid or not (i.e. drilling fluid, water . . .)

- Annulus above top of cement is full of fluid
  - o Before setting heavy duty clamp; run two Macaroni pipe strings at different sides of 13 ⅜"x18 ⅝" annulus to top of cement, or to a maximum depth of 200 ft.
  - o Mix and pump 125 pcf cement slurry through the macaroni pipes until annulus is filled with cement.
- Annulus above top of cement is empty
  - o Lower 2" line few feet down the annulus.
  - o Fill cement slurry at lowest rate.
  - o Wait long enough for cement to settle down and top up the cement column to surface by pumping additional cement down the annulus.

9.2.2 13 ⅜" Casing Landed on Casing Hanger Mandrel

In case when Casing Hanger Mandrel is used to land the 13 ⅜'' casing, the 13 ⅜"x18 ⅝'' annulus can not be accessed by macaroni pipe.

Conduct top job by pumping cement through the Casing Head Mandrel outlets as follows:

- Annulus above top of cement is full of fluid.
  - o Connect cementing line to the side of the Casing Head outlet. Figure 2-28.
  - o Pump enough 125 pcf cement slurry down the annulus to displace the fluid into the lost circulation zone and to push cement column down to the base of the lost circulation zone.
  - o Ensure that pump pressure do not exceed 500 psi to avoid collapse of the 13 ⅜" casing.
- Annulus above top of cement is empty.

- o Fill cement slurry down annulus at lowest rate keeping other CH Mandrel side outlet open to atmosphere. Watch for returns from 2nd outlet.

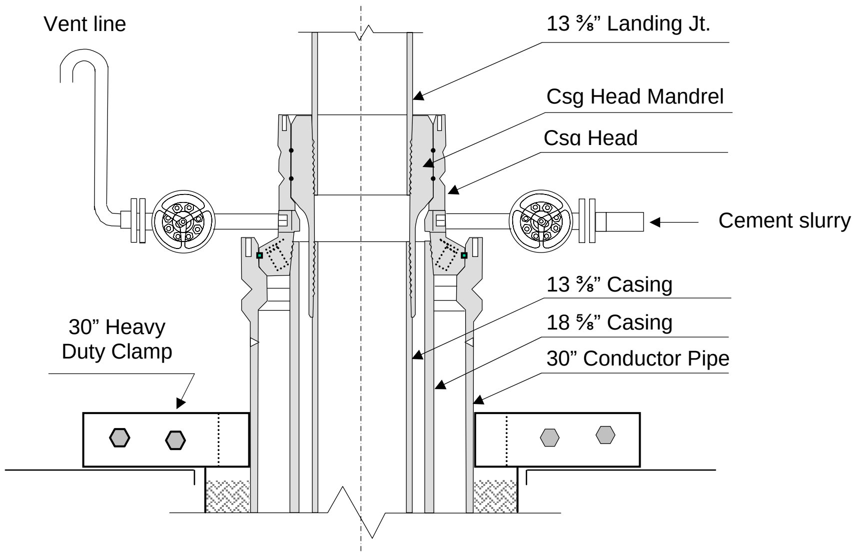


Figure 2-28: Top job of 13 ⅜"Casing in case of empty annulus

10. Potential Drilling Hazards

Table 2-18: Potential Drilling Hazard for 17 ½" Hole

Potential Hazard	How to mitigate
water flow or loss of circulation, especially in areas close to the sea.	**Understanding the Miocene and Dammam formation:** • Miocene clastics consisting mainly of Limestone and Marls. This section is unconsolidated and can dump sand and stones into the well bore around drill string. This occurs when fluid level drops due to losses while drilling Dammam formation. • Dammam consists of marly limestone. This is a potential thief zone or water flows, especially the top 200 ft. **Drill surface hole cautiously:** • Review offset wells prior to spudding the well • In case of sudden losses, try to continue drilling with control GPM and ROP, circulate at least bottom up prior to POH. • Watch carefully while drilling top 150 ft in Dammam • Be prepared to fill hole down annulus at maximum possible pumping rate • Drill with the maximum possible GPM (more than 850 GPM), watch shale shaker carefully and ensure hole clean
Stuck drill string due to Miocene heaving following sudden and severe losses	• Closely monitor losses while drilling top hole. Massive dilution of water will be required to maintain mud weight. Use viscous gel sweeps on connections, if required, to clean the hole. • Agree with Driller and Rig Manager the initial action to be taken

Potential Hazard	How to mitigate
into top Dammam	for each problem that is likely to happen. • Don't apply more than 30,000 lb over pull, if needed, run back to bottom and circulate while rotating at high speed.
Stuck casing due to hole cleaning, hole geometry, loss/flow or tight hole	• Stick to the BHA specified in the drilling program. • Avoid creating ledges by easing bit in harder formation and reaming transition between formations. • Watch casing string weight, understand and monitor casing drag up and down. • Avoid thick mud cake by controlling fluid loss and solids. • Circulate hole clean prior to POH for casing • Survey check with Totco at bottom.
Damage of bit cutting Structure in Rus	Rus anhydrite is significantly harder than Damman Basal shales above it. Negative Drill break practices are required when entering the Rus. (decrease RPM and hold WOB constant or increase slightly).
Bit Balling	Balling may take several forms, which are classified by where the balling occurs: global balling (entire bit and/or stabilizers), teeth balling, or bottom balling. Balling usually occurs in shales, and with water based muds. In 17 ½" section, balling is likely to be either global or teeth balling in mill tooth bit or both. All types of balling can be reduced by having a sufficiently inhibitive mud. Global Balling risk will be reduced by consistently high flow rates, and good hole cleaning. Teeth balling risk exists in Dammam Basal Shale, and UER Basal Shale. • Ensure of pumping at high flow rates, and sufficient HSI (>2). • With tri-cone bits, centre jet and oriented nozzling will also aid preventing balling (oriented nozzling directs part of the flow onto the cutting structure). • Avoid excessive WOB while drilling through these formations. **Actions once balling has been detected:** • Bits can be cleared if balling is detected early enough and actions taken. • Reduce WOB when ROP drops, pick up bit off bottom as quickly as possible and increase flow rate. • Spin bit off bottom with high RPM and high flow rate for 5 minutes • Resume drilling with very low weight • Prepare to pump pills (high concentration glycol pill (15-20%) and fresh water pill), leave to soak and try to dissolve/loosen balled material Prepare to trip if these actions are not successful and choose more optimum, bit, hydraulics nozzling arrangement or mud system

11. Wellhead

For the 13 ⅜" casing (either set on Casing Hanger Mandrel or Heavy Duty Clamp) two types of Casing Head Housing systems are used: "Threaded CHH" system and "Slip on Lock CHH".

11.1 Threaded Casing Head Housing

- The threaded type Casing Head Housing (CHH) is made up to a 1 ft 13 ⅜" nipple (pin x pin). The assembly is made up in DWS and dispatched to the rig prior to the job. Figure 2-29 and Figure 2-30.
- After cementing 13 ⅜" casing and laying down riser or diverter.
- Make up the casing head running tool to CHH assy.
- Lower the CHH assy and make up to the 13 ⅜" "Casing Hanger Mandrel" and torque, position the outlets to the desired orientation (ensure the bottom connection reaches the base of the triangle mark on the pup joint). Ensure the top flange is leveled using water balance.
- Remove CHH running tool.
- Nipple up 13 ⅝" Blowout Preventer.

11.2 Slip on Lock Casing Head Housing

- After cementing 13 ⅜" casing and laying down riser or diverter, make up 13 ⅜" pup joint to Casing Hanger Mandrel and torque.
- Cut 13 ⅜" pup joint as close to Casing Hanger Mandrel as possible, ensure the bevel is smooth and without any sharp edges.
- Make up the running tool to Casing Head Housing (CHH).
- Lower the Casing Head Housing until it lands on top of the 13 ⅜" pup joint stub (position the outlets in the correct orientation); weight maybe required to install the head over the casing stub. See Figure 2-31.
- Remove running tool. Ensure top flange is leveled using water balance.
- Pressure test the CHH seals to 80% of the 13 ⅜" casing collapse pressure.
- Torque the CHH nuts.
- Install Blowout Preventer (BOP).

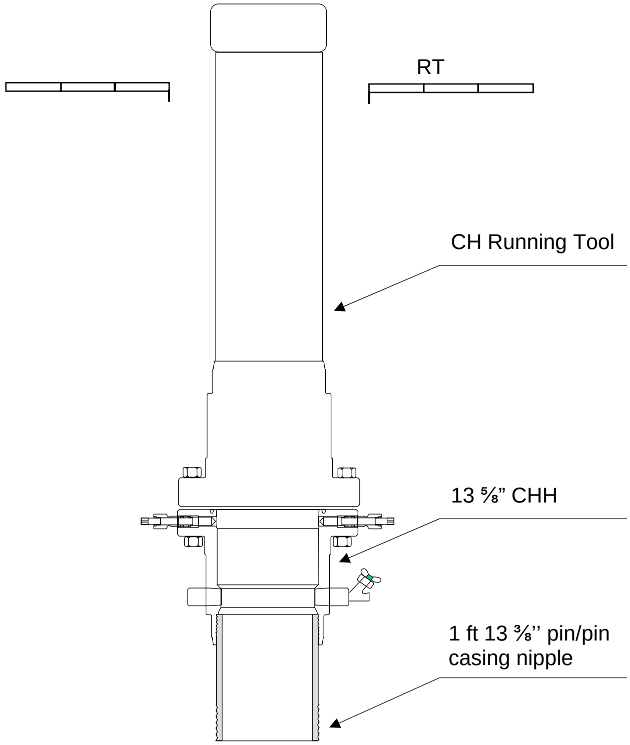


Figure 2-29: Running 13 ⅝'' CHH through rotary table

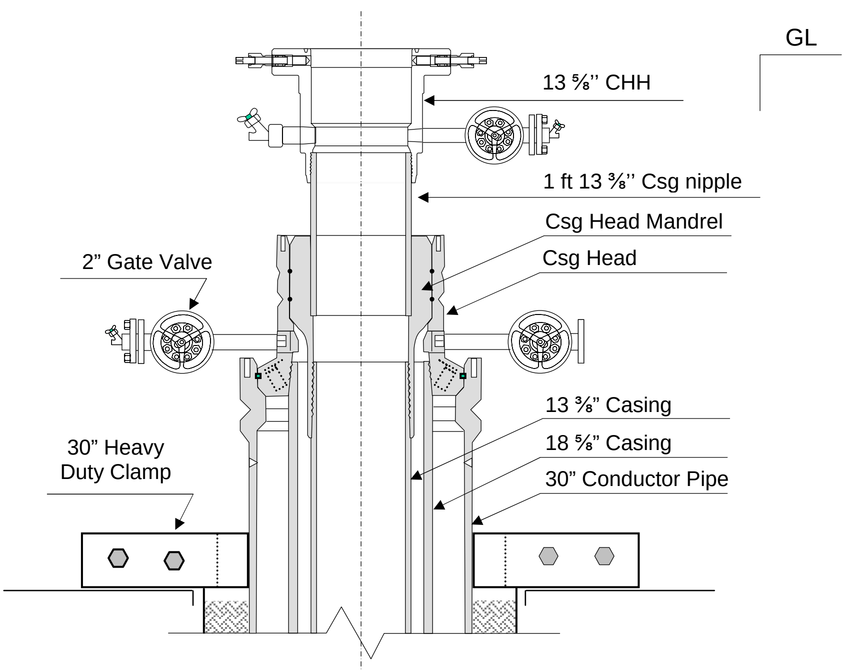


Figure 2-30: 13.5/8" Thread Type CHH after landing 13 ⅜'' casing

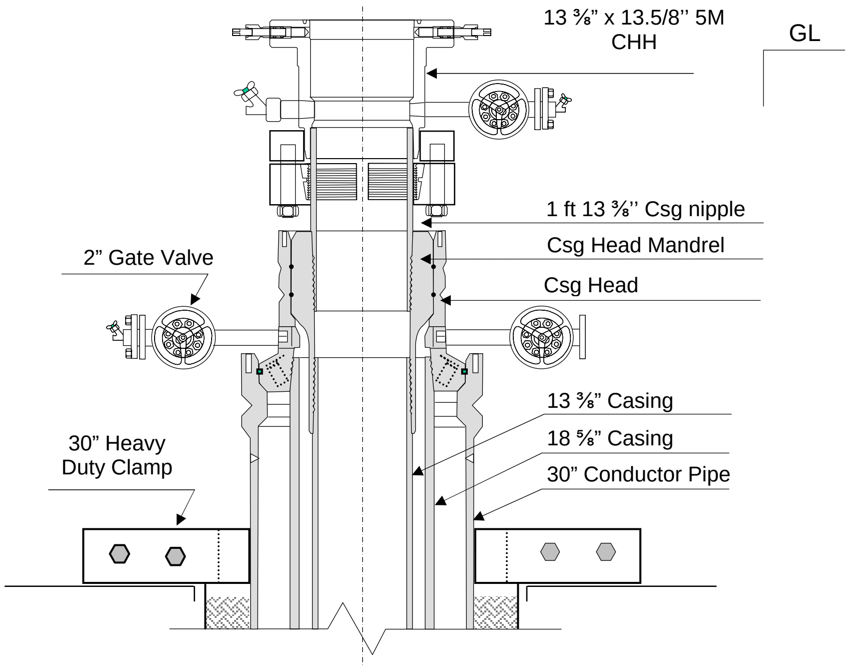


Figure 2-31: 13 ⅜" Slip on Lock CHH after landing 13 ⅜'' casing

12. Blowout Prevention

BOP stacks in ADCO are classified into 4 categories:

- (**I**) (Ann 5000 psi + 3 Rams 10000 psi equipped with 35% H_2S elastomers).
- (II) (Ann 5000 psi + 3 Rams 5000 psi equipped with 35% H_2S elastomers).
- (III) (Ann 5000 psi + 2 Rams 5000 psi equipped with 35% H_2S elastomers).
- (IV) (Ann 5000 psi + 2 Rams equipped with 5% H_2S elastomers).

See Figure 2-32 and Figure 2-33

Refer to the Chpater-3, "well Control" of this volume for selecting the proper BOP's stack minimum requirement.

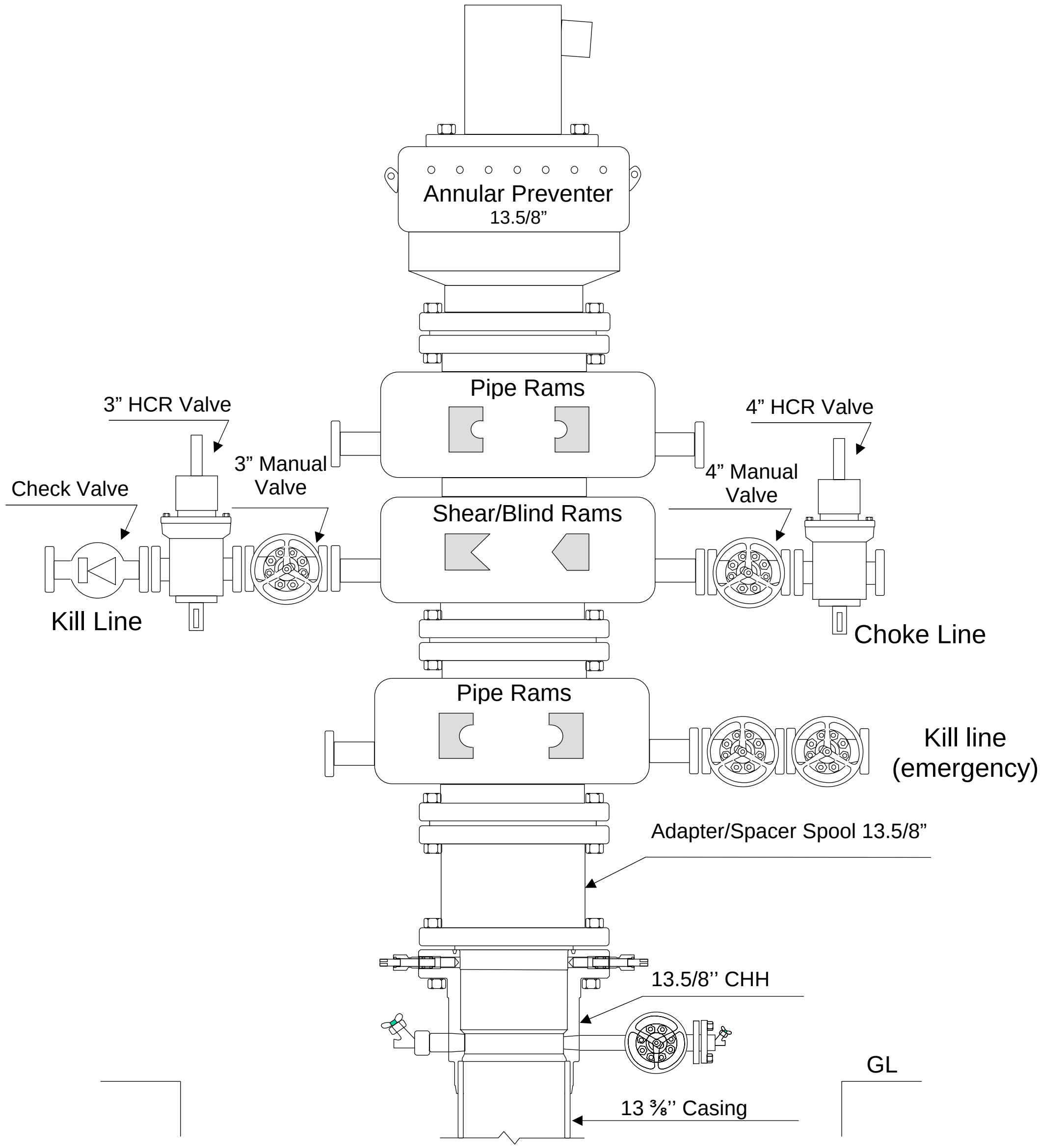


Figure 2-32: Class (I) & (II) BOP Stack

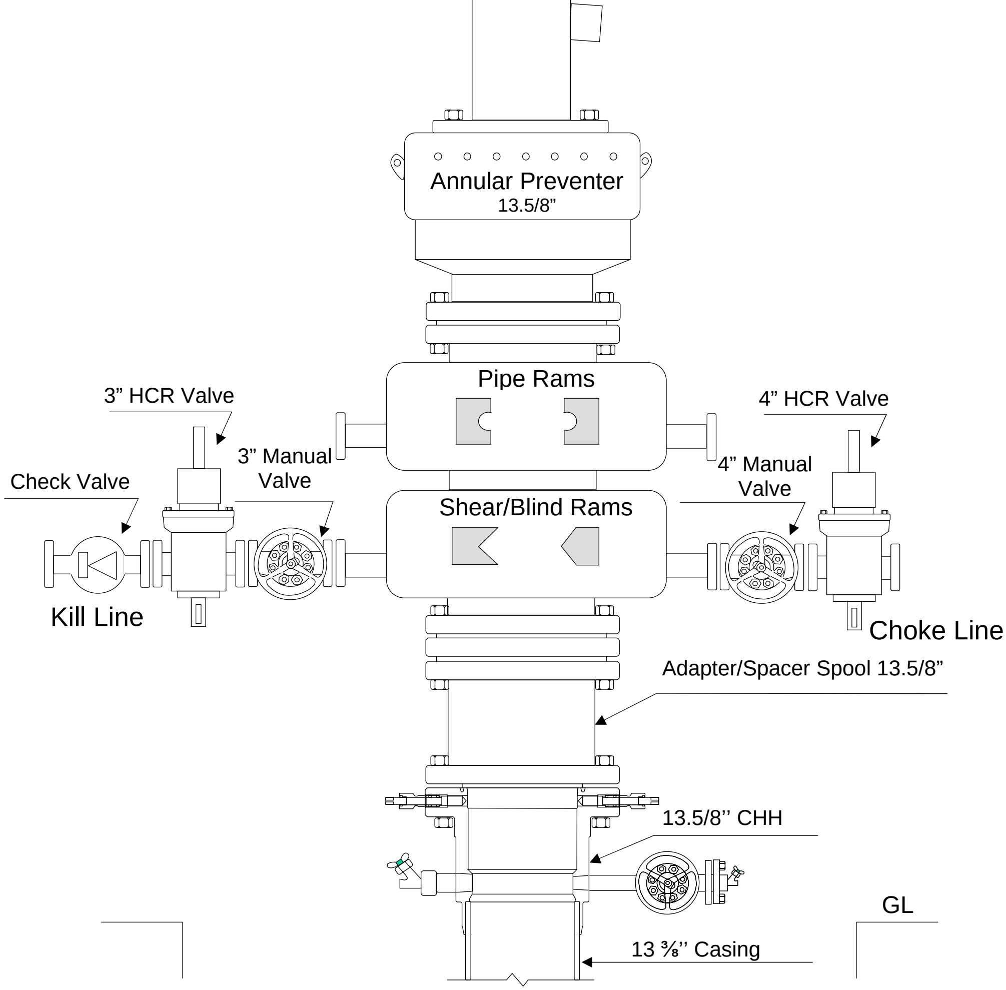


Figure 2-33: Class (III) & (IV) BOP Stuck

12.1 Installation

- Pressure test casing Head Housing to 1000 psi, do not exceed 60% of the 13 ⅜" of casing burst pressure.
- Nipple up 13 ⅜" spacer on top of the 13 ⅜" x 13 ⅝" - 5000 psi Casing Head Housing (Plan for installing the rotating head at later stage by adjusting the length of spacer).
- Nipple up 13 ⅝" BOP. Connect choke line, kill line and valves, function test the entire BOP components.

Note:
In case where 13 ⅜" casing is set at top Dammam and the 9 ⅝" casing is set into Shilaif, no Blowout Preventer is required unless otherwise specified in the well program.

12.2 Pressure Testing

- Open Annulus on the CHH valve.
- Pick up the Combination Test Plug (CTP) and lower it slowly until it lands on the load shoulder of the CHH.
- For pressure testing through the Drill pipe, remove all four ½” LP plugs from the weep holes and leave the center 1 ¼” LP plug in (leave the four plugs when testing through Kill line).
- For BOP function test, accumulator pre-charging test and BOP test refer to Chapter-3 “Well Control” of this volume.

Note:

The tie-down screws (in Tubing Head Spool or Casing Head Housing must be fully retracted prior to pulling on the wear bushings. Failure to do that would cause damage to the wear bushing and lock screws. If the defected test plug or wear bushing are to be re-used, it will cause subsequent damage to the THS/CHH seal area.

13. Equipment Required

The following equipment is required for the 17 ½” phase:

13.1 Tubular and Casing Equipment

Table 2-19: 13 ⅜” Casing and Accessories

S.N.	Description	Grade	Wt lb/ft	Thread	MESC No.
1	Casing, R3	K-55	68	BTC	04.08.03.520.1
2	Float Collar (N.R)	K-55	61 - 72	BTC	05.14.26.620.9
3	Float Shoe	K-55	61 - 72	BTC	05.14.17.622.9
4	O.H. Centralizer	-	-	-	05.17.25.160.9
5	Positive Centralizer	-	-	-	05.17.30.168.9
6	Stop Collar	-	-	-	05.17.55.125.1
7	Casing dope	-	-	-	87.47.25.07.09
8	Thread compound	-	-	-	87.42.47.24.09

Dimensions, mechanical properties and make up torque of the 13 ⅜” casing:

Table 2-20: 13 ⅜” Casing properties

Description	ADCO Wells	ADNOC Wells
Body OD (Inch)	13 ⅜”	13 ⅜”
Grade	K-55	L-80
Weight with collar (lb/ft)	68	68
Connection	Buttress	Premium

Description	ADCO Wells	ADNOC Wells
Min. ID (inch)	12.415	12.415
Drift diameter (inch)	12.259	12.259
OD of coupling(inch)	14.375	14.375
Capacity (bbls/ft)	0.1497	0.1497
Body yield strength (klb)	1069	1556
Coupling yield strength BTC (klb)	1069	1556
Collapse pressure (psi)	1950	2260
Burst pressure (psi)	3450	5020
Make up torque optimum (ft.lb)	20,650 (Triangle)	20,650

13.2 Wellhead

Equipment required for the 13 ⅜" wellhead is:

Table 2-21: 13 ⅜" Wellhead Equipment

13 ⅜" Casing Landing Method	Heavy Duty Clamp	Casing Hanger Mandrel
Wellhead equipment required	13 ⅜" Heavy Duty Clamp	Casing Hanger Mandrel
	CHH 13 ⅜" Buttress x 13 ⅝" 5M with two 2.1/16" stdd outlets (either threaded or slip on lock type)	CHH 13 ⅜" Buttress x 13 ⅝" 5M with two 2.1/16" stdd outlets (either Threaded or Slip On Lock type)
	2.1/16" Gate valve	2.1/16" Gate valve
	2" Bull Plug	2" Bull Plug
	Gauge	Gauge
	Pup joint 13 ⅜" (pin x pin)	Pup joint 13 ⅜" (pin x pin)

14. Waste Management

Hole Size	Mud Salinity	Rental Equipment		Mud Handling	Cuttings Handling
17 ½"	Water Base Mud	Tanks	4	NO DUMPING Excess mud to be transported to injection disposal well.	Cuttings to be piled on location and to be used to bund the location.
		Centrifuge	2		

- No waste pits should be dug, use instead a 300 bbls tank to collect waste mud and then transfer to the waste disposal site.
- Environment inspection checklist to be filled in at least weekly and sent to office.
- Ensure sewage treatment unit discharge analysis is meeting ADNOC regulations.

12 ¼” HOLE FOR 9 ⅝” CASING

The 9 ⅝’’ casing in ADCO is the production casing string, run and set in 12 ¼’’ hole through or just above the production or injection interval

1. Purpose

1.1 12 ¼” Hole to Bottom Shilaif

To set 9 ⅝’’ casing in Shilaif when usable TVD is insufficient to drill the 8 ½” build section. 9 ⅝” casing is set Into Shilaif to case-off Aquifers prior to drilling the Nahr Umr shale with 8 ½’’ bit (vertical, deviated or slanted) and land the 7’’ liner in the reservoir.

1.2 12 ¼” Hole to Top Bab Member

To set 9 ⅝” casing just above the production/injection zones when usable TVD is sufficient to drill the 8 ½” build section, 9 ⅝” casing is set just above the production or injection zone, isolating Nahr Umr prior drilling the curved section to land the 7’’ liner in the reservoir, Prior to drilling the horizontal section.

1.3 12 ¼” Hole through Reservoir

To set 9 ⅝’’ casing across the top reservoire zones/units prior to drilling other deeper zones.

2. Applications

The 12 ¼’’ hole may be drilled vertical or deviated in different scenarios depending on the application. Figure 2-34 shows the various 12 ¼’’ hole scenarios.

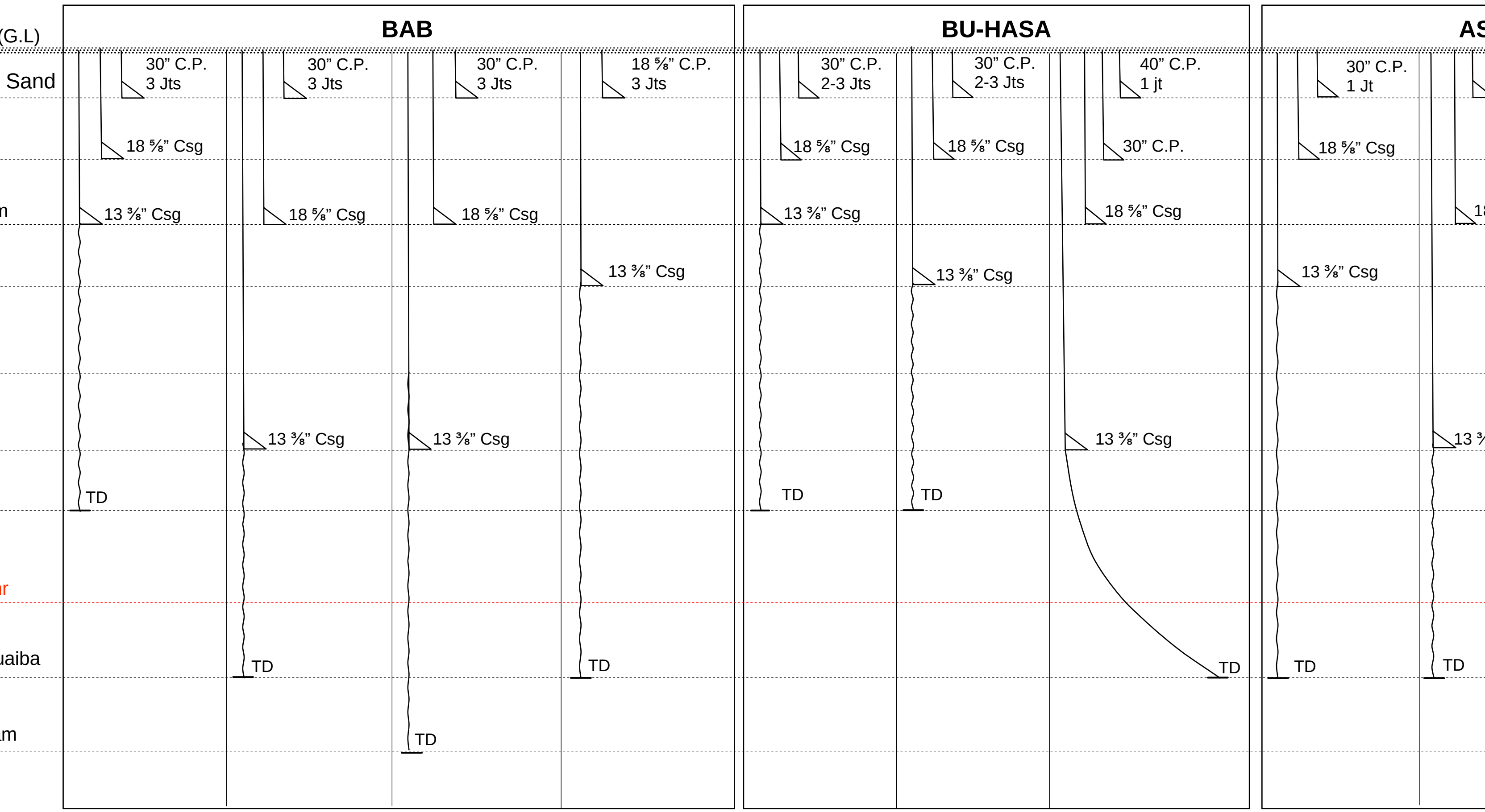
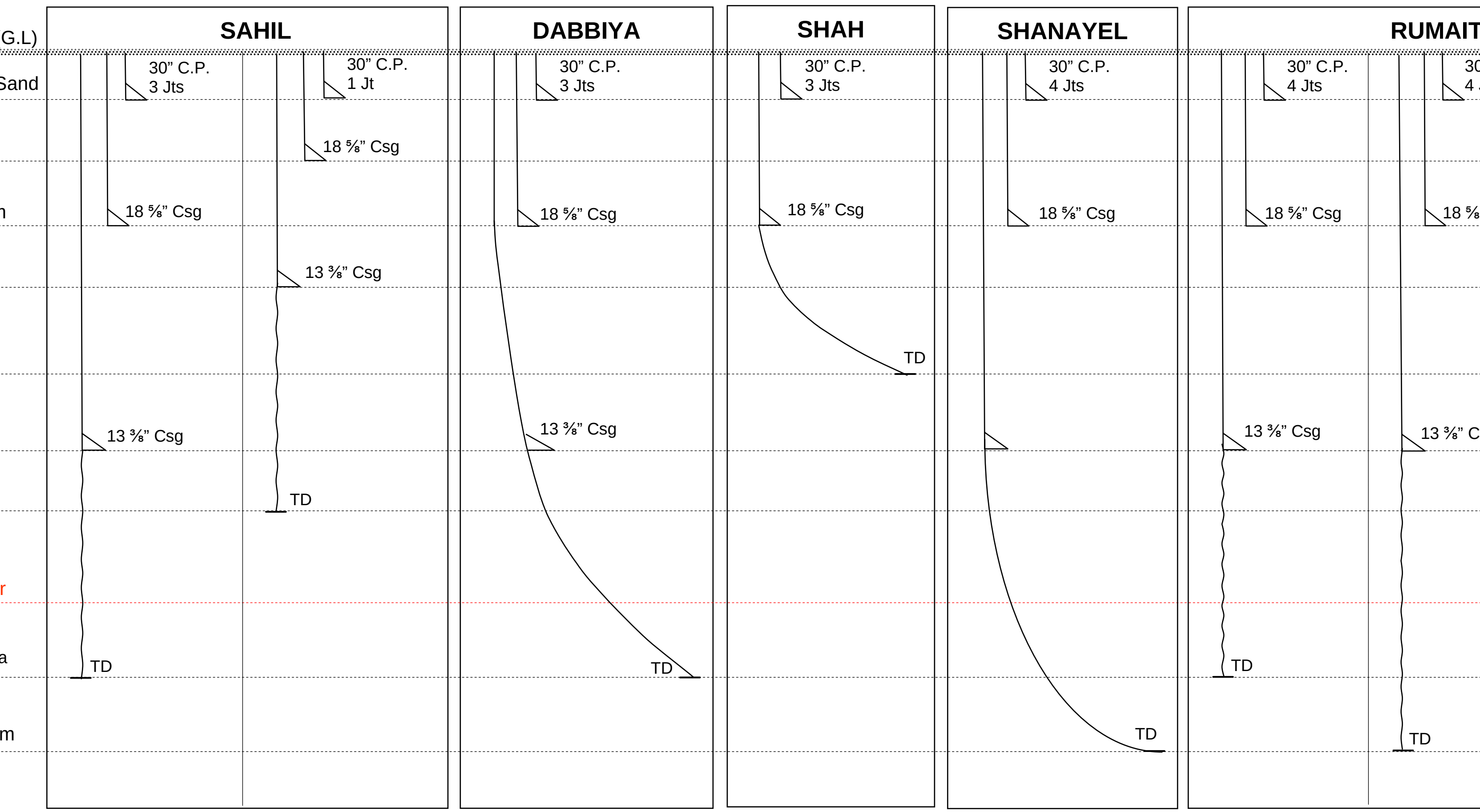


Figure 2-34: ADCO's Typical 12 ¼" Phase


G.L)
Sand
n
r
a
m
SAHIL
30" C.P.
3 Jts
30" C.P.
1 Jt
18 ⅝" Csg
18 ⅝" Csg
13 ⅜" Csg
13 ⅜" Csg
TD
TD
DABBIYA
30" C.P.
3 Jts
18 ⅝" Csg
13 ⅜" Csg
TD
SHAH
30" C.P.
3 Jts
18 ⅝" Csg
TD
SHANAYEL
30" C.P.
4 Jts
18 ⅝" Csg
TD
RUMAIT
30" C.P.
4 Jts
18 ⅝" Csg
13 ⅜" Csg
TD
TD

3. Preparations and Offline Operations

3.1 During Drilling 12 ¼” Hole

- check and test 8 ½” MWD and LWD on surface
- Test cement unit and cement lines while running casing.
- Ensure that all 9 ⅝” casing and accessories are available, serviced and ready (i.e. elevator, single joint elevator, slips, spider elevator, spider slips, casing bowl, casing tongs, casing thread protectors).
- Prepare 9 ⅝” casing install shoe, float collar and centralizers.
- Rig up power tong for running casing while circulating at bottom.
- Make up fluted mandrel hanger, running tool and pack off bushing running tool

3.2 During Nippling up BOP

- Record gyro survey inside 9 ⅝” casing, (if Gyro steering is not required in the next phase).
- Make up BOP’s test plug with one joint drill pipe.

4. Drilling 12 ¼” Hole

- Run in hole with 12 ¼” bit and BHA and tag top of cement/float collar.
- Conduct KILL DRILL to familiarize crew with well control.
- Drill float collar, cement, shoe and 10 ft new formation.
- Conduct shoe bond test to maximum of 0.65 psi/ft EMW if 13 ⅜” casing is set into Rus or Fiqa).
- Continue drilling 12 ¼“ hole to 9 ⅝” casing point.
- Proceed as follows if 13 ⅜” casing is set into Rus or shallower, and aerated drilling technique is required to drill UER and Simsima:
    - o Nipple up rotating head on top of 13 ⅝” BOP.
    - o Run in hole with 12 ¼” bit.
    - o Drill 12 ¼” hole to top Fiqa using aerated mud system.

- Refer to “Special Drilling Operations”, ADM, Volume-2 for detailed aerated drilling procedures.
- At top Fiqa decrease air gradually, stop air at bottom Fiqa, pump high viscosity pills and continue drilling observing well for losses. Incase of losses, continue to drill with aerated mud to casing point at bottom Shilaif. If no losses, displace well to KCL PHPA mud and continue drilling to casing point at Bab member.
- Nipple down flow line and rotating head and nipple up conventional flow line and bell nipple.

- Proceed as follows if 12 ¼” hole is to be kicked-off:
  - Run Gyro survey across 13 ⅜” casing prior to starting drilling.
  - Drill 12 ¼” vertical hole to KOP.
  - From a rock strength perspective, the best formations to kick-off in are the base Fiqa, Ruwaydhah, Tuwayil or Mauddud. The kick off point should be selected based on the well departure and the vertical section required
  - Run Gyro, orient tool face, kick off and drill 12 ¼” directional hole to the planed build up section
  - Record MWD every 100 ft from 13 ⅜” casing point to the kick off point for tie-in purposes.
  - The Bent Housing should be selected such that it delivers sufficient dogleg and kick off capability, at the same time allowing for efficient rotation inside the casing whilst drilling the float equipment
  - Continue drilling directional hole as per drilling program. Tangent hole across Nahr Umr is always recommended.
  - Rotary steerable systems should be considered when BUR is less than 5^o/100 and the hole section is more than 3000 ft.
  - Mud weight should be designed to control the Nahr Umr and avoid differential sticking across the reservoir (refer to Chapter-5, Mud Guidelines of this Volume).
  - Hole cleaning is a vital whilst drilling deviated hole across Nahr Umr.
  - At 12 ¼’’ TD, circulate hole clean. Pump sweeps of L.V.M followed by H.V.M., ream down if necessary and pull out of hole.

4.1 Drill String and BHA Design Considerations

- A motor assembly or RSS will be run to drill this section.
- The assembly will contain two Roller Reamers / Stabilizers.
- Configure BHA’s to be as short and light as possible. Minimize non magnetic equipment, without sacrificing survey accuracy.

- All Stabilizers / Roller Reamers shall be gauged prior to use. Undergauge stabilizers shall be changed out except when required for directional purposes. When utilizing undergauge stabilizers, ensure sufficient carbide dressing thickness remains on the stabilizer to protect the stabilizer from excessive wear. All stabilizers should be well tapered both top and bottom.

- All BHA components should have a bore back box, stress relief pin and cold rolled threads.

- Incompatible ID's and OD's of mating components, should not be run as they present an area of high stress concentration that are more likely to incur fatigue failure.

- Subs with lengths less than twice the hole diameter shall not be run in the BHA.

- The Drilling Contractor and service companies shall maintain records of equipment usage, inspection and maintenance on the rig e.g. jar rotating hours, downhole motor circulating hours.

- The number of drill collars in the BHA will be determined by the W.O.B. utilized on offset wells, maximum W.O.B. rating for bit type and anticipated mud weight. The minimum number of collars shall be run at all times.

- Drilling jars shall not be run in the neutral position (Optimize jarring system and placements. Get jar manufacturer to run optimization programme and advise for BHA's proposed).

- ID's in the BHA shall be larger than the OD of any tools that may be required to pass through that part of the BHA.

- All tools run below RT to be drawn up and all dimensions logged.

- A ported float valve is to be installed in the string.

- Select bent housing on motors to produce adequate dog leg severity (DLS) without minimizing housing fatigue in rotary mode.

- Consider PDM rotor/stator interface for maximizing life.

- Consider using variable gauge stabilizer to control rotary mode directional tendencies and improve hole cleaning.

- Run smallest amount of stabilizer commensurate with directional stability to ensure optimal performance while sliding.

- If a BHA does not perform in directional mode do not hesitate to trip out as this could lead to a poor hole quality and unnecessary high torque and drags.

- Change bit designs incrementally and ensure they are compatible with BHA. Treat the bit as an integral part of the assembly.

- Ensure drillstring design accommodates WOB for all types of bit to prevent buckling of the drillstring.

- Recommended 12 ¼" drilling assembly.

Option 1: Motor drilling – Directional

Table 2-22: Recommend Directional BHA for drilling 12 ¼" hole

Size	Description	No.	Comments
12 ¼"	Motor insert bit	1	Motor Insert bit, 4-3-5, 5-1-7, or 6 bladed 16mm-13mm PDC, (centre jet, mini extended nozzles on insert)
9 ⅝"	Motor	1	(fitted with 12 1/8" sleeve stab)
12 ¼"	Roller Reamer	1	
	MWD	1	
8"	Oriented sub	1	
8"	N.M.D.C	1	
12 ¼"	Roller Reamer	1	
8"	N.M.D.C	1	
8.1/4"	DC	12	
8"	Drilling Jar	1	
8.1/4"	D.C	3	
7"	D.C	3	
X Over	X Over Sub	1	
5"	HWDP	9	

Option 2: Motor drilling – Directional with flex joint

Table 2- 23: Recommended Directional BHA for drilling 12 ¼" with flex joint

Size	Description	No.	Comments
12 ¼"	Motor insert bit	1	Motor Insert bit, 4-3-5, 5-1-7, or 6 bladed 16mm-13mm PDC, (centre jet, mini extended nozzles on insert)
9 ⅝"	Motor	1	(fitted with 12 1/8" sleeve stab)
8.1/4"	Flex Joint	1	
	MWD (Power Pulse)	1	
8"	N.M.D.C	1	
12 ¼"	Roller Reamer	1	
8"	N.M.D.C	1	
8.1/4"	DC	12	
8"	Drilling Jar	1	
8.1/4"	D.C	2	
7"	D.C	3	
X Over	X Over Sub	1	
5"	HWDP	9	

Option 3: Motor drilling – Vertical

Table 2- 24: Recommended BHA for Drilling Vertical 12 ¼" Hole with Motor (1)

Size	Description	No.	Comments
12 ¼"	Insert bit or PDC	1	Motor insert bit, 4-3-5, 5-1-7 or 5 blades 16 mm – 13 mm PDC, (center jet, mini extended nozzles on insert)
9.1/2"	Motor	1	Slick
12 ¼"	Roller Reamer		
8"	DC or MWD	1	Totco ring
12 ¼"	Roller Reamer	1	
8.1/4"	DC	12	
8"	Drilling Jar	1	
8.1/4"	DC	2	
7"	D.C	3	
X Over	X Over	1	
5"	HWDP	9	

Option 4: Motor drilling – vertical

Table 2-25: Recommended BHA for Drilling Vertical 12 ¼" Hole with Motor (2)

Size	Description	No.	Comments
12 ¼"	Insert bit or PDC		Motor insert bit, 4-3-5, 5-1-7 or 5 blades 16 mm – 13 mm PDC, (center jet, mini extended nozzles on insert)
9 ⅝"	Motor		Fitted with 12.1/8" sleeve stab
9.1/2"	Float sub		Totco ring
12 ¼"	Roller Reamer	1	
8.1/4"	DC	1	
12 ¼"	Int. Blade Stab	1	
8.1/4"	DC	12	
8"	Drilling jar	1	
8.1/4"	DC	2	
7"	D.C	3	
X Over	X Over sub	1	
5"	5" HWDP	9	

Option 5: Rotary drilling – Pendulum

Table 2-26: Recommend Rotary BHA for Drilling 12 ¼" Hole

Size	Description	No.	Comments
12 ¼"	Rock bit or PDC	1	Bit, 4-3-5 or 5-1-7
Bit Sub	Bit Sub	1	Equipped with float sub and Totco ring
8.1/4"	DC	2	
12.1/8"	S. Stab	1	
8.1/4"	DC	16	
8"	Drilling Jar	1	
8.1/4"	DC	3	
8.1/4"	X Over	1	
7"	DC	3	
X Over	X Over Sub	1	
5"	HWDP	9	

- Changes may be made to the above recommended BHA's depending on the hole trajectory, target and hole condition.

4.2 Directional Drilling

4.2.1 Directional Planning Recommendations

- Steerable assemblies should be designed so that build can be achieved with 70-80% rotation if possible. This will result in better quality hole, smoother wellbore profile, (less torque and drag) hole cleaning efficiency and overall better drilling/tripping performance and generally speaking, less hole problems.
- Use as low build rates as target constraints allow:
  - This will result in lower tortuosity
  - Build up rate through the reservoir sections must not exceed the minimum through which MWD and LWD tools can be rotated. This is to allow logging of formation tops to pick the correct landing point.
  - Low build up rates result in lower contact forces, i.e. reduced casing wear.
- Torque and drag should be considered for top and bottom of hole interval as a minimum requirement using realistic friction factors for maximum weight on bit required (roller cone and PDC bits) in both sliding and rotary drilling modes.
- All MWD deviation data will be quality checked using approved software.
- If formation walk tendencies are known, consider leading the target azimuth in the tangent section to avoid deeper steering requirements.
- Avoid planned steering or kick-off in Nahr Umr Shale formations, if possible. Tangent profile across Nahr Umr is best suited for this.
- The DS must make regular checks, with the directional driller/MWD operators to ensure no manual manipulation of the directional survey data is occurring.

4.2.2 Borehole Surveying and Logging While Drilling Program

Accuracy prior to drilling into potential reservoir is seen as the critical issues for surveying requirements. (e.g. to ensure accuracy should a relief well need to be drilled.)

The following surveying programme will be adopted.

Table 2- 27: Surveys required for 12 ¼" hole

Survey and Logging Instrument type	Survey Frequency	Remark
Gyro In 13 ⅜" casing. MWD/PWD + (CDR)	Directional surveys every stand, reducing the frequency as applicable. Continuous PWD MWD/PWD + (CDR)	Contingency: Multishot at TD or on trips include NMDC/totco ring

- Main justification for using MWD/CDR is for the use of the Pressure Measurement while Drilling sub (PWD).
- Gyro to tie in for accuracy prior to drilling into reservoir targets.
- MWD IHR shots to be taken on every trip in hole to ensure accuracy of data.

4.2.3 Directional Challenges

Table 2- 28: Directional Challenges for 12 ¼" hole

Formation	Directional Issues
Shilaif	• Potential for chert in top Shilaif. • Hard formation. Slow kick off. Sliding slowly to build angle. Predictable directional performance. • Common bit damage due to formation strength.
Mauddud	No major issues.
Nahr Umr	• Drop tendency towards middle of formation. • Unpredictable walk rate in rotary mode. • Common poor bit performance for formation strength due to bit being damaged while drilling the Shilaif formation above. • If the Suhaiba / Thamama formations are drilled in the same hole section as the Nahr Umr, the increased mud weight will make sliding difficult due to differential sticking, also possible formation damage issue

4.3 Drilling Optimization

4.3.1 Bit Selection

- The 12 ¼" section is entirely PDC drillable. The target is one PDC per section.
- The standard type of PDC bit is a medium set PDC (5 or 6 blades), with large cutters (mostly 19mm, although smaller is sometimes used on gauge).
- Stability features are desirable, especially for the vertical motor performance drilling, where no bit or motor stabilization is used. Stability features aid in reducing cutter damage due to bit whirling effects.

- The main challenges to a PDC bit cutting structure are 1) the Rus anhydrite. Particularly when starting a PDC run in this formation, extra care needs to be exercised with parameters, in order to maintain good cutting structure from the beginning of the run; 2) the Umm Er Radhuma basal shale is hard, and can also contribute to cutter damage; 3) Top Simsima can also be hard; 4) Thereafter, interbed sections require drilling parameter optimisation.

4.3.2 Hydraulics and Nozzles Selection

High ROP's dictate that hole cleaning, and hence sufficient flow rate, be a primary objective. Thereafter, hydraulic optimization can focus on maximising HSI. This is particularly important for water based muds (especially for ROP through the claystones), and the use of PDC bits. It is recommended to aim for HSI > 3.

4.3.3 Hole Cleaning

- Pump rates from 900 to 1100 gpm are commonly used, however this depends on the individual rig specs and limitations.
- Minimum recommended pump rates are approximately 700 gpm for vertical, and 800 gpm for build section.
- The above recommendations are very generic, and each application should be analysed accordingly. Factors influencing hole cleaning include: flow rate, annular cross-sectional area (hence drill pipe OD), mud rheology and mud weight, cuttings size, inclination, drill pipe rotational speed, length of sliding intervals (zero pipe rotation), drill pipe eccentricity, ROP.
- The shale shakers should be monitored regularly by the Drilling Supervisor, as well as by the mud engineer. The shape, quantity and condition of the cuttings give valuable indications of what is happening downhole. Supervisors should check the shakers at frequent intervals and this practice must be continued.
    - Refer to hole cleaning section in Chapter 4, Drilling Optimization of this volume.
    - Anomalies should be reported to Town immediately.

4.3.4 Motor

- 9 ½" (or similar e.g. 9 ⅝"), medium speed motors are standard for performance drilling.
- Smaller sized motors can be used, for example 8", but careful consideration needs to be given to flow rate limit. A smaller

motor size than 9 ½" (or similar) might be required where a more flexible assembly is wanted to give higher build rates. However, maximum flow rate limitation of 8" motors (or similar), needs to be taken into consideration.

4.3.5 Drilling Parameters

- Operate at the weight on bit, pump rate and rotary speed (if needed) that gave the highest penetration rate in the drill-off tests, unless significant losses problem is expected
- Avoid operating parameters that lead to drill string vibrations. Use a rotary speed that is high enough to give smooth rotation of the drill string, but not so high that axial and/or lateral drill string vibrations or bit whirl occur.

4.3.6 General Drilling Practices

- Keep the applied weight on bit smooth once it has been optimized. Feed weight continuously to the bit using the Driller's electric brake if available and avoid "slack-off / drill-off" - this can contribute to damaging BHA due to torsional vibrations.
- Reduce the applied weight on bit, pump rate and/or rotary speed as necessary to ensure that the penetration rate does not exceed the maximum allowable ECD.
- When running a BHA of increased stiffness, expect to have to ream. Do not trip into the open hole rapidly. If the hole is thought to be under gauged, extreme caution must be applied when tripping into the hole.
- Whilst drilling between formations, many rock strengths may be encountered. The interface between rocks of relatively low and high strengths is a classic environment in which harmful vibrations are initiated. Drill string severe vibration should be minimised to prolong bit life, improve drilling efficiency in drilling longer intervals and also to minimise damage to downhole tools
- Monitor and record the depths and magnitude of drags, overpull, and any rotary torque (if rotation was necessary) to help assess the condition of the hole
- If increasing resistance is experienced during tripping out (that cannot be wiped free.) the assembly will be pumped out of the hole monitoring drag and pump pressure, circulating as required. A decision to wiper trip back to bottom will be made at this stage.

- Never try to force the string through a tight spot. Pulling firmly into tight hole, may lead to the string becoming stuck.

- Take it carefully and do not pull more than half the weight of the collars below the jars. If this rule is followed, it should always be possible to work the pipe back down. This gives the Driller a figure to work to and will prevent many stuck pipe incidents each year.

- Depending on the situation, the Drilling Supervisor has the option of gradually increasing the overpull, each time checking that the pipe is free to go down. At any stage, the top drive can be used to wash down and work the pipe.

- Never pull more than the weight of the collars, as this will almost certainly result in the string becoming stuck.

5. Drilling Fluid

The drilling fluid type used in this phase depends on the field as well as the casing setting formation. For more details, refer to Chapter-5 “Mud Guidelines” of this volume.

6. Running 9 ⅝” Casing

- If 9.5/8” is set into reservoir, then retrieve wear bushing, change pipe rams to 9.5/8” and test to 3000 psi or maximum anticipated pressure at surface.

- Use floats equipped with float valves (NRV) and not auto fill-up valves

- Activate NRV prior to run casing in hole.

- Install casing shoe on the pin of the first joint and float collar on the box of the second joint (Two joints shoe track), using thread-locking compound.

- Do not tag-weld the shoe and float collar.

- Flow check float equipments.

- Run casing in hole, filling every three joints. Monitor mud tank level, trip sheet, and consistent increase on casing string weight; ensure casing is taking the calculated volume.

- For deviated hole, placement and number of open hole centralisers should be simulated using computer model to have 80% standoff.

- Install open hole centralisers as follows:
  - 1 OH Cent. 5 ft above shoe over stop collar.
  - 1 OH Cent. 20 ft above shoe over stop collar.

- 2 OH Cent. on the centre of each the first 3 joints, (over stop collar).
- 1 OH Cent. each 3 joints, (over stop collars) on the centre of the joint until 13 ⅜" casing shoe.

- Positive centralisers: One centraliser 10 ft below cellar and another one 20 ft below it, then 2 centralizers every joint for the following 3 joints and finally one centralizer every 3 joints for remaining cased hole.
- Keep all pipe movement smooth and steady. Check returns to monitor any mud losses.
- Run 9 ⅝'' casing to bottom. Circulate and reciprocate casing until shale shakers are free of cuttings. (Minimum one cycle).
- If casing is held up, don't push casing. Circulate and reciprocate casing until there is return and casing free, continue run in hole with circulation, then circulate bottoms up if the held up point is close to bottom otherwise pull out casing and run with cleaning assembly.
- Space out for installing the fluted mandrel hanger, Figure 2-35.
- Install fluted mandrel hanger in the last joint of casing, make up running tool and casing landing joint and install cementing head.
- Land 9 ⅝" casing on CHH loading shoulder. Figure 2-36
- When casing reaches bottom, start circulating at 15 BPM while reciprocating casing continuously at 10 ft up and down. After casing drag up and down stabilises, increase circulation rate to 20 BPM for 1 to 1.1/2 cycles. Keep circulating until the shale shaker is clean before pumping cement.
- Record rig pump volumetric efficiency for both pumps at this stage and correlate with corresponding pump strokes.
- Record circulating losses if any and keep pipe moving slowly on a 10 ft stroke to avoid differential sticking (Do not exceed the 70% of weakest pull capacity of the system).

7. Landing Casing

- Stop reciprocation, slack off running tool until fluted mandrel hanger lands in the casing head housing, then reduce the casing weight to zero.
- Proceed with cementing operation.

8. Cementing 9 ⅝" Casing

9 ⅝'' casing must be cemented with sufficient cement to fill the annular space from the shoe to the surface. If there are indications of improper cementing such as lost

returns, cement channeling, or mechanical failure of equipment, corrective measures must be taken until a satisfactory cement integrity is obtained.

Cement 9 ⅝'' casing as follows:

- In case of Water Base Mud, pump the following spacers ahead of cement at 15 BPM minimum rate.
  - 300 Bbls L.V. Mud of same mud weight.
  - 40 Bbls Location Water and 30 Mix water.
- In case of Oil Base Mud, use 50 Bbls of cement spacer including surfactant (recipe based on Lab testing).
- Mix and pump Lead slurry; use batch mixer for mixing tail slurry.
- Cement recipes are as per ADCO Lab formulations which are based on field samples of water and cement.

Table 2- 29: 9 ⅝" Casing Cement Slurry

Casing Setting Formation	Spacer Ahead	Slurry Type	
		Lead Slurry	Tail Slurry
Shilaif Bab Member Shuaiba / Thamama	40 Bbls Location Water and 30 Bbls Mix Water	Light weight cement slurry	Class G cement slurry (118 pcf)

- Volume of cement based on 60% excess for O. H. and 10% for casing / casing volume.
- Drop plug and displace cement with 10 Bbls location water (when Water Base Mud is being used) or 10 Bbls unweighted spacer (if O. B. M is in use) and complete displacement with mud. Displacement to be performed at 15 BPM minimum rate. If losses occur, this rate must be reduced to 6 BPM (ME to monitor losses during displacement by checking level in mud tanks and by observing returns at shale shaker).
- Bump plug at 2500 psi for 5 minutes. (If plug is not bumped don't over displace, pump only theoretical volume).
- Release pressure and check for back flow.
- Flush casing hanger profile with water, make the hanger pack off bushing and run down to land on top of the fluted mandrel hanger.

8.1 Cement Top Job

- At the primary cementing job, one of the two following cases could happen:

- o The cement can never be pump higher in the annulus than the lost circulation zone. In this case there will be always a fluid above lost circulation zone.
- o The cement reached to surface but dropped again to a level which can not be exactly anticipated. In this case there will be no fluid from top of cement to surface.

- Monitor annuals carefully during primary cementing. And define if annulus is full of fluid or not.
- Connect cementing line to one side of the CHH outlets

Case 1: severe loss, cement did not return to surface, annulus above top of cement is full of fluid. The following to be done immediately after the primary cement job or

- Mix and pump enough cement slurry down the annulus to displace the fluid into the lost circulation zone and to bring cement column up to the base of the lost circulation zone.
- Install pressure gauge in the other side of the CHH outlets
- Watch pressure carefully, ensure annulus pressure do not exceeds 500 psi surface pumping pressure
- Flush CHH valves

Case 2: Cement returned to surface and dropped back, annulus above top of cement is empty.

The following to be carried out after 6-8 hours W.O.C..

- Fill cement slurry down annulus at lowest rate keeping other CHH side outlet open to atmosphere
- Top up the cement column to surface by pumping additional cement down the annulus.

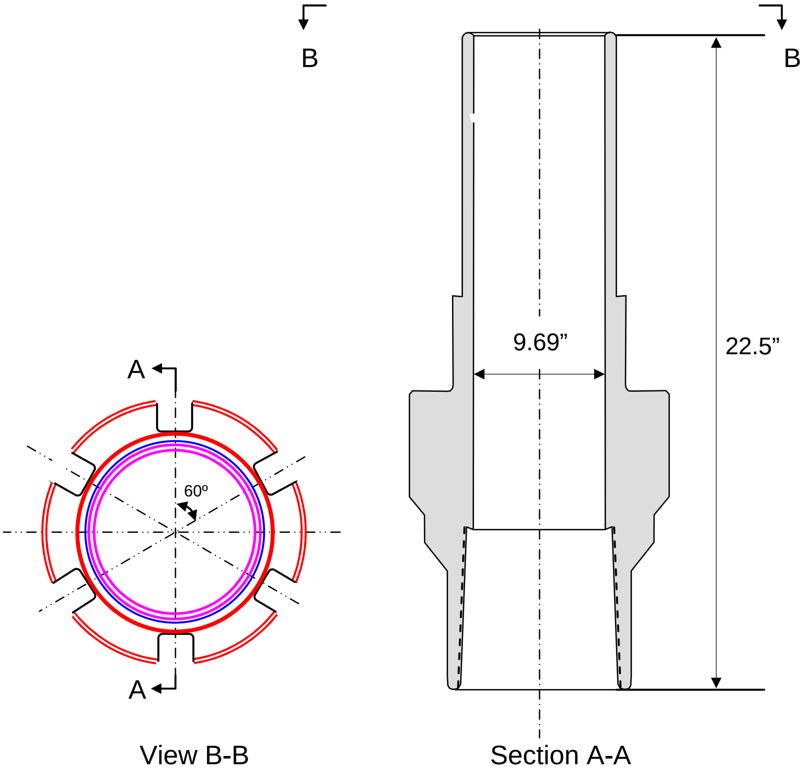


Figure 2-35: 9 ⅝” Fluted Hanger Mandrel

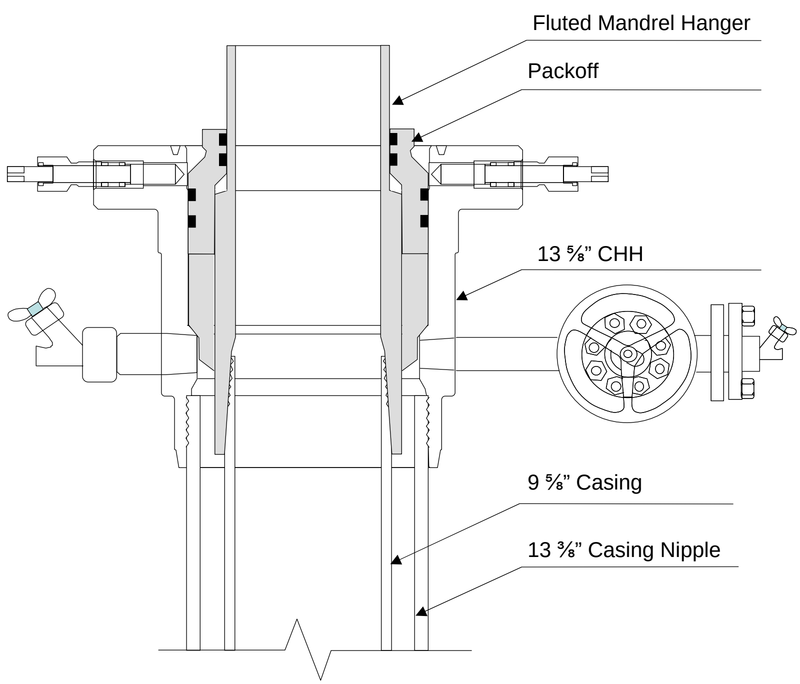


Figure 2-36: 9 ⅝” casing landed on CHH with Fluted Mandrel Hanger after cementing

9. Drilling Hazards

Table 2- 30: Drilling Hazards in 12 ¼" Hole

Potential Hazards	How to mitigate
Loss circulation in aquifers	• UER consists of porous limestone and dolomites providing very fast drilling. Chert can occur near the base. UER is a potential loss zone due to its high porosity. • Simsima consists mainly of soft limestone and with variable porosity. It is a potential loss and flow zone due to high porosity and fracturing. This hazard is usually encountered near the top of the formation. Time of the occurrence (while drilling, circulation or tripping), type of loss (seeping, partial or complete) with respect to the exposed formations should be considered. This information will help determine why the loss occurred, where in the hole the loss occurred and the best remedy for the situation. • As losses have appeared, drill a few feet but do not drill more than 60 feet. • Pull-up the bit to a point of safety and the hole permitted to remain static for a period of 4 hrs. • Carefully run back to bottom and keep minimum pressure surge to the formation. • Start drilling with minimum parameter and sweep hole with 100 Bbls High filter-loss LCM pill. • Prepare to spot conventional LCM plugs with OEDP or with bit without nozzles.
Shale instability	• Nahr Umr Shale has proven to be unstable at varying hole angles, although there are no apparent problems drilling it vertically. • Raise mud density immediately if long slender pieces of Laffan or Nahr Umr shale started coming over the shakers • Nahr Umr, Halul, Laffan and Ruwaydhah formations must be drilled with inhibited mud (mud weight must ensure stability even if severe losses encountered). • Minimize Number of trips across Nahr Umr. • Control tripping speed and rotation speed across Nahr Umr. This will prevent swabbing and mechanical damage due to drill string harmonic vibration. • The Nahr Umr Shale is time dependent to WBM and Polymer muds and the shale becomes difficult to control after 7-10 days exposure. Always try to drill and case Nahr Umr shale as fast as possible
Differential sticking	• The mud weight must minimize the risk of differentially stuck pipe when crossing the zones within the reservoir objective. • A contradiction exists whereby high mud weight is required to stabilize the Nahr Umr Shale and a low mud weight is required to avoid differential pressure and fluid loss when drilling the reservoir. There are several specialized "bridging " products that reduce seepage thereby reducing the likelihood of differential sticking in low permeability zones

Potential Hazards	How to mitigate
	• Install string stabilizers within the drill string to ensure 'stand-off' from the wellbore. This could compromise directional (build) capability. • Ensure preventative drilling practices are strictly adhered to (i.e. moving and rotating drill-string as much as possible, minimizing length of unstabilised BHA, use of spiral Drill Collars and HWDP). These measures however may not be practical in wells where the build to horizontal is a critical objective • Control water loss, minimize mud cake building tendency. • Monitor filter cake quality. • Use of Rotary Steerable Systems will minimize overall contact with the wellbore and will reduce the tendency for differential sticking, particularly in longer extended reach wells. • Solids removal equipment should be used with full performance and efficiency
Tight hole	• While drilling with aerated mud, maintain high fluid pumping rates above 850 GPM. • Increased air to mud ratio associated with high ROP can cause cuttings to accumulate above BHA at sections where low fluid velocity exists. If this condition continues, and cuttings accumulate in the annulus: i) hydrostatic head increases ii) losses occur in the lower formation iii) differential sticking is possible iv) hole pack off could also occur during connection. • Use aerated fluid of maximum 56 pcf equivalent density. • Minimize time spent at connections without pipe motion. • Consider wiper trip at top Simsima if hole condition dictates. • Stabilize BHA using roller reamers. • To minimize chances of stuck pipe, avoid pulling above 30 klb. • Do not fight your way in or out of the hole. • In case of sudden complete loss, try to continue drilling with controlled GPM and ROP, circulating at least one bottom up prior to POH.
Drill string corrosion	• High O_2 content in aerated mud accelerates corrosion, especially where the drill string coating is broken. • Inspect drill string regularly. • Use 8% sodium silicate, inhibited with bentonite to reduce corrosion rate.
Ledging and hole spiraling	• Ledging can be an issue when drilling alternate hard and soft formations particularly at an angle. This can occur when drilling through the reservoir zones. Ledging occurs generally at the top of the harder formations at the interface when whirl or other lateral instability is induced due to the reduced depth of cut. This can be reduced or eliminated by following negative drill break practices and easing the bit into the harder formation. • Poor weight transfer to the bit can also produce ledging and hole enlargement by reducing the depth of cut at the bit, thus initiating lateral instability and whirl.

Potential Hazards	How to mitigate
	• Hole spiraling is likely to occur when rotary drilling with a motor and bent housing. Bit whirl / off-center rotation is induced by the action of rotating the bent housing. The higher the bend angle the more likely hole spiraling will occur. To overcome this problem a long gauge bit or turbo-back stabilizer can be used. Another method of reducing hole spiraling is to reduce the distance from bit face to bent housing. • Review the offset wells for problems encountered.
Poor hole cleaning	Hole angles between 45º and 65º present the most problems with drilled cuttings having a tendency to slide down the annulus and 'pack-off'. Hole angles greater than 65º do not present additional problems in this regard since the drilled cuttings are supported by sliding friction against the wellbore and become more stable as discrete cuttings beds. Use good hole cleaning practices to prevent formulation of cutting beds (Rotation, High GPM, Thin Sweeps. . .)

10. Blowout Preventer

No change is brought to the BOP in this section; same BOP configuration of the 17 ½" is used.

Refer to Chapter-3 "Well Control" of this volume on BOP classification, installation and test.

11. Equipment Required

The following equipment is typically required for the 12 ¼" phase:

11.1.1 Tubular and casing equipment

Table 2- 31: 9 ⅝" Casing and Accessories

S. N.	Description	Grade	Wt lb/ft	Thread	MESC No.
1	Casing, R3	L-80	47	N.VAM	04-12-15-370-9
2	Casing, R3	L-80	47	NK3SB	04-12-88-370-9
3	Casing Pup (5')	L-80	47	N.VAM	04-12-16-205-9
4	Casing Pup (10')	L-80	47	N.VAM	04-12-16-210-9
5	Casing Pup (20')	L-80	47	N.VAM	04-12-16-220-9
6	Casing Pup (5')	L-80	47	NK3SB	04-12-89-205-9
7	Casing Pup (10')	L-80	47	NK3SB	04-12-89-210-9
8	Casing Pup (20')	L-80	47	NK3SB	04-12-89-220-9
9	Float collar (N.R)	L-80	43.5–47	VAM	05-14-26-610-9
10	Float shoe	L-80	43.5-47	VAM	05-14-17-668-9
11	Float collar (N.R)	L-80	43.5-47	NK3SB	05-14-26-612-9
12	Float shoe	L-80	43.5-47	NK3SB	05-14-17-750-9
13	O.H. Centralizer	-	-	-	05-17-25-126-9
14	positive Centralizer	-	-	-	05-17-30-135-1

S. N.	Description	Grade	Wt lb/ft	Thread	MESC No.
15	Stop Collar	-	-	-	05-17-55-110-1
16	Casing Dope	-	-	-	87.47.25.07.09
17	Thread Compound	-	-	-	87.42.47.24.09

Dimensions, mechanical properties and make up torque of the 9 ⅝" casing is tabulated in the following table:-

Table 2- 32: 9 ⅝" Casing Properties

Description	
Body OD	9 ⅝"
Grade	L-80
Weight lb/ft with collar	47
Connection	Premium
Min. ID	8.681"
Drift diameter	8.525"
OD of coupling	10.625"
Capacity Bbls/ft	0.0732
Body yield strength klb	1,086
Coupling yield strength BTC klb	1,086 (same for N VAM)
Collapse pressure psi	4,750
Burst pressure psi	6,870
Make up torque optimum ft.lb	11,500

11.1.2 Wellhead

Table 2- 33: 9 ⅝" Casing Wellhead

S. N.	Description	Quantity	Mesc No.
1	Fluted casing hanger 13 ⅝" x 9 ⅝"	1	09.20.22.865.9
2	Tubing Head Spool 13 ⅝"x11"– 5 M	1	09.21.40.635.9

12. Waste Management

<table>
<tr><th>Hole Size</th><th>Mud Salinity</th><th colspan="2">Rental Equipment</th><th>Mud Handling</th><th>Cuttings Handling</th></tr>
<tr><td rowspan="7">12 ¼"</td><td rowspan="2">Water Base Mud</td><td>Tanks</td><td>4</td><td rowspan="2">NO DUMPING
Excess mud to be transported to injection disposal well.</td><td rowspan="2">NO DUMPING
Excess mud to be transported to injection disposal well.</td></tr>
<tr><td>Centrifuge</td><td>1</td></tr>
<tr><td rowspan="5">Oil Base Mud</td><td>Air Pumps</td><td>1</td><td rowspan="5">NO DUMPING
Mud to be stored for either recycling or to be transferred to injection disposal well</td><td rowspan="5">Cuttings to be drayed using H "G" dryer and transferred to cutting treatment plant into sealed cutting boxes.</td></tr>
<tr><td>Auger</td><td>2</td></tr>
<tr><td>Tanks</td><td>6</td></tr>
<tr><td>Centrifuge</td><td>1</td></tr>
<tr><td>G Dryer</td><td>2</td></tr>
</table>

- No waste pit should be dug, use a 300 bbls tank instead to collect waste mud and then transfer to waste tanks.
- Environment inspection checklist should be filled at least weekly and sent to office.
- Ensure discharge from sewage treatment unit meets ADNOC regulations.

Notes:

1) Ensure all OBM cutting boxes are not damaged.
2) Fill only 3/4 capacity of OBM cutting box.
3) Ensure minimum solid content of the OBM cutting in boxes are 70%.
4) Ensure all boxes are covered on trucks by Tarpaulin.
5) Hi “G” Dryer to be used after the shale shaker through an Auger to reduce the fluid content of the cutting up to 70%. Cutting to be collected in cutting boxes and the recovered fluid is to be pumped to storage tanks for disposal.

8 ½“ HOLE FOR 7” PRODUCTION LINER

1. Applications

The 8 ½” hole trajectory is a function of the requirements for ADCO’s operations.

- Usable TVD (difference between TVD at KOP and landing point TVD).
- Build up rate desired to drill the curved section to the landing point.
- Departure desired (vertical to landing point)
- The most cost effective way of drilling the section.

One of the following scenarios may be applied:

Case 1

To set 9 ⅝” casing at bottom Shilaif, and kick off with 8 ½“ bit at 100 - 500 ft below the casing shoe, then drill build-up section to the landing point.

Case 2

To set 9 ⅝’’ casing at top Shilaif and then drill 8 ½“ vertical section with PDC bit as deep as possible to the kick-off point. Kick off using tricone, or short guage PDC bit, and build up to the landing point.

Case 3

If a long departure is required, set 9 ⅝’’ casing at top Shilaif, then run directional BHA and 8 ½“ bit to drill long build up section with tangent section across Nahr Umr

Case 4

To set 9.5/8” casing at Bab Member, then run directional BHA and drill build up section to the landing point.

The 8 ½“ hole in ADCO is typically drilled deviated. 7” liner is run and cemented to provide separation of the productive horizons from other formations.

The drawings bellow illustrate the different applications of the 8 ½“ hole in each field.

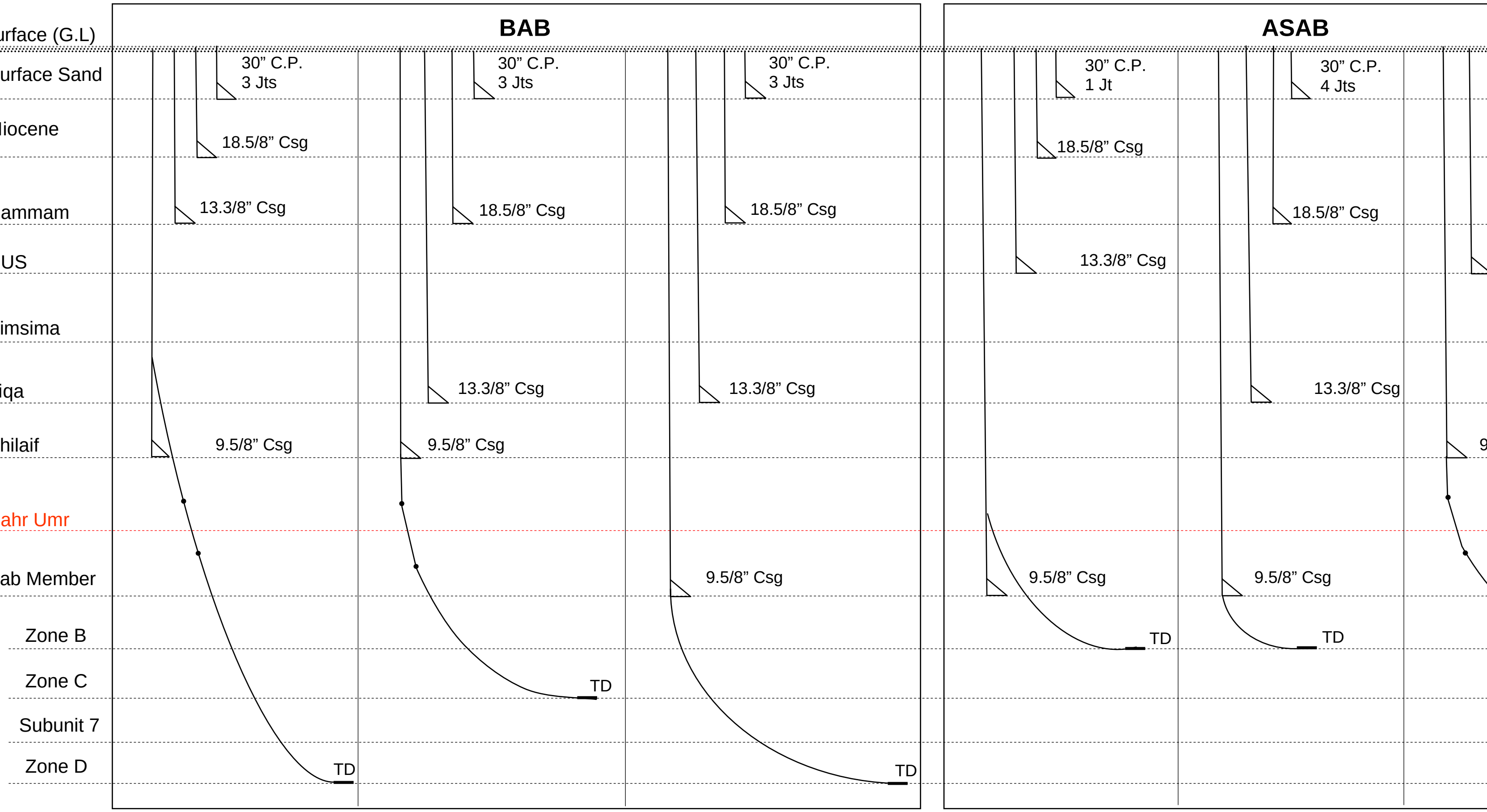
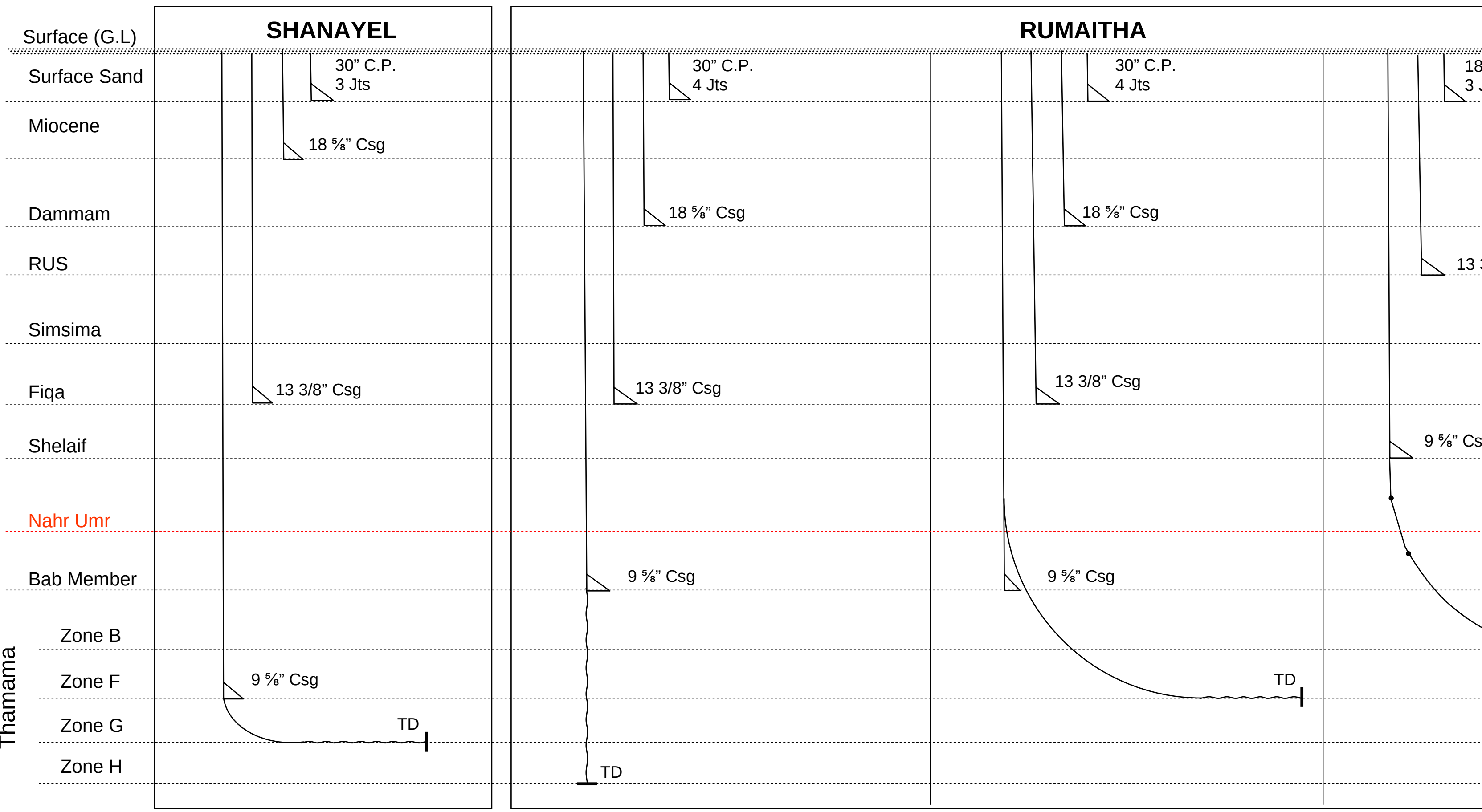


Figure 2-37: ADCO's Typical 8 ½" Phase


SHANAYEL
RUMAITHA
Surface (G.L)
Surface Sand
Miocene
Dammam
RUS
Simsima
Fiqa
Shelaif
Nahr Umr
Bab Member
Thamama
Zone B
Zone F
Zone G
Zone H
30" C.P.
3 Jts
18 ⅝" Csg
13 3/8" Csg
9 ⅝" Csg
TD
30" C.P.
4 Jts
18 ⅝" Csg
13 3/8" Csg
9 ⅝" Csg
TD
30" C.P.
4 Jts
18 ⅝" Csg
13 3/8" Csg
9 ⅝" Csg
TD
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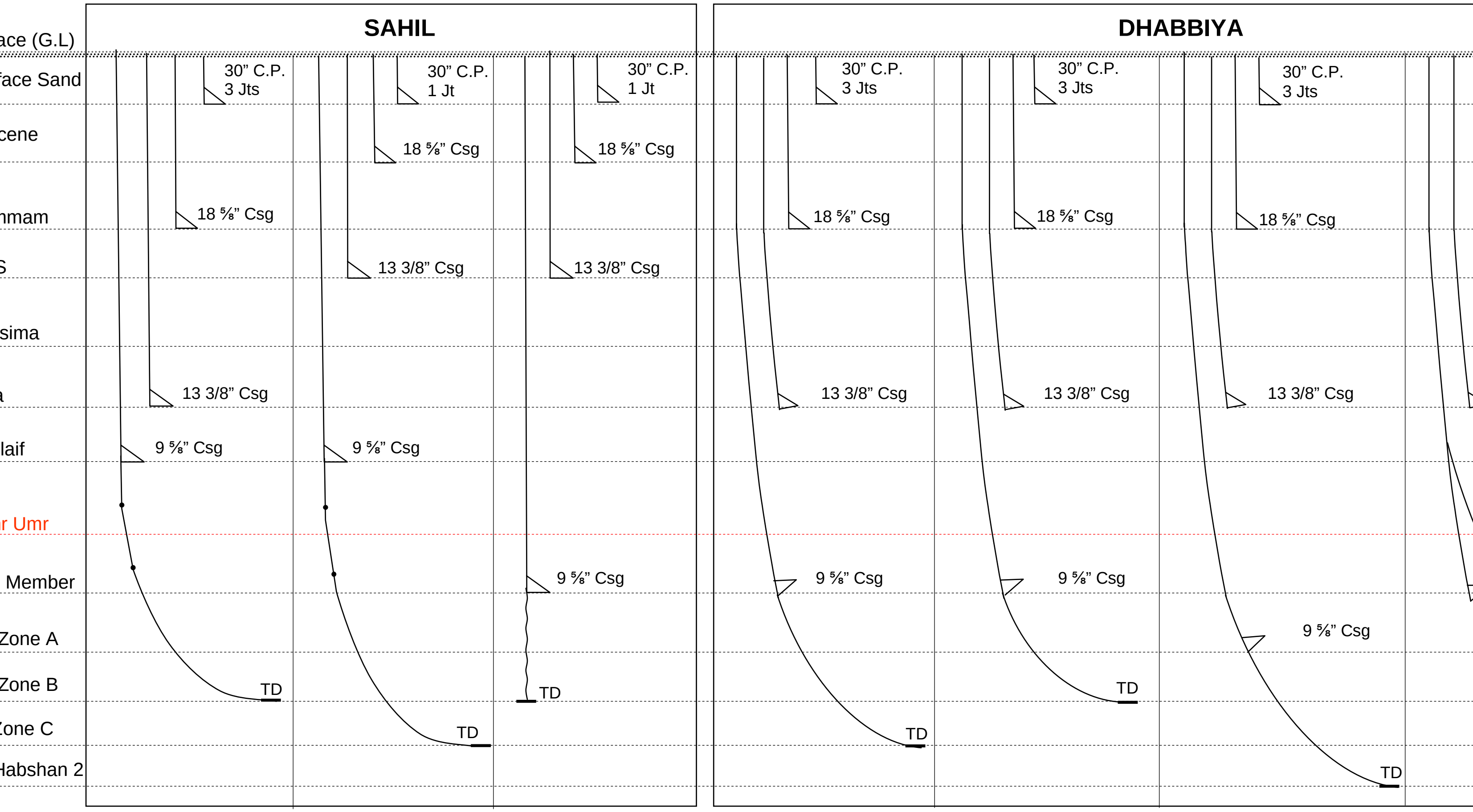
13
9 ⅝" Cs


SAHIL
DHABBIYA
ace (G.L)
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laif
r Umr
Member
Zone A
Zone B
Zone C
Habshan 2
30" C.P.
3 Jts
30" C.P.
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30" C.P.
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18 ⅝" Csg
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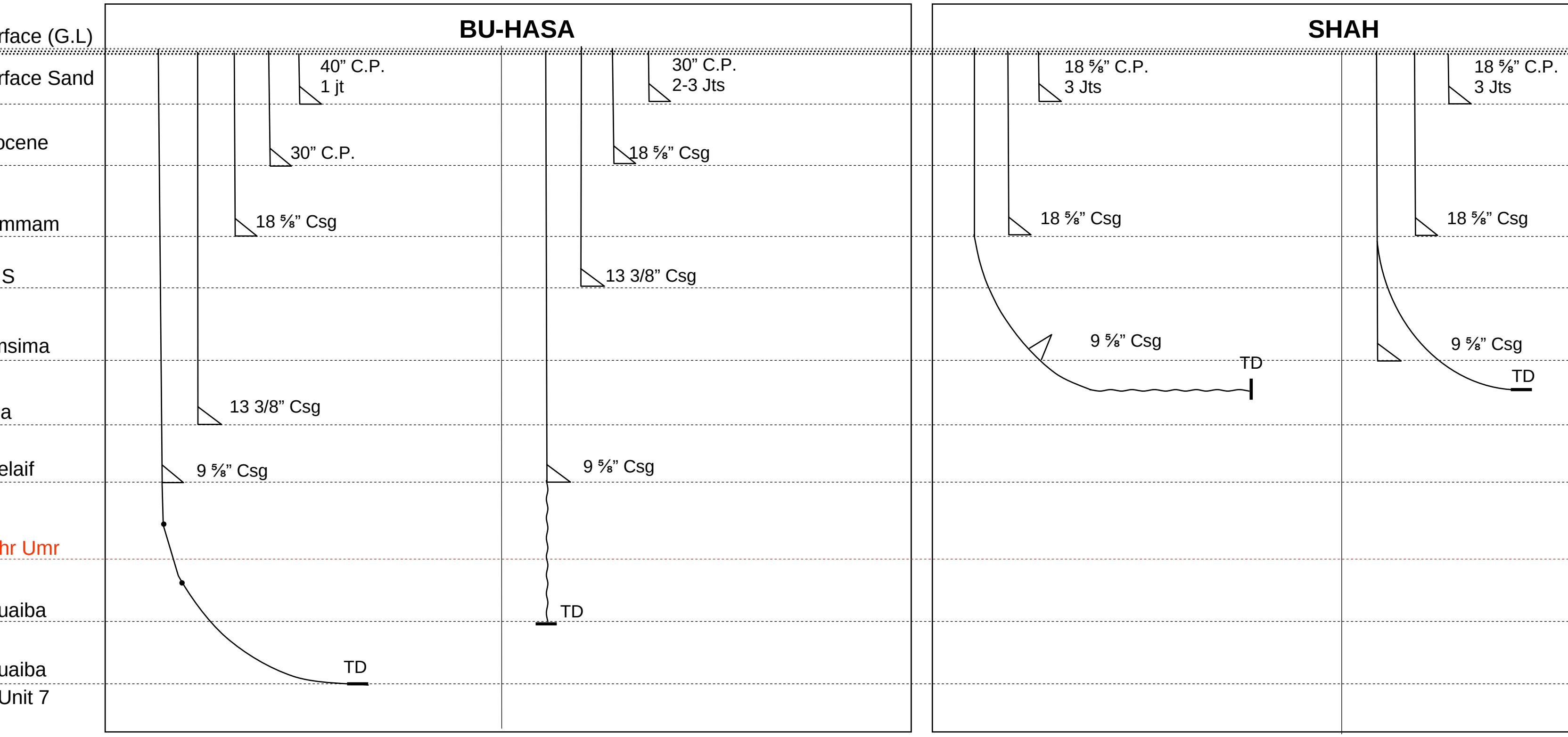
rface (G.L)
rface Sand
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S
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a
elaif
hr Umr
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uaiba
Unit 7
BU-HASA
40” C.P.
1 jt
30” C.P.
18 ⅝” Csg
13 3/8” Csg
9 ⅝” Csg
TD
30” C.P.
2-3 Jts
18 ⅝” Csg
13 3/8” Csg
9 ⅝” Csg
TD
SHAH
18 ⅝” C.P.
3 Jts
18 ⅝” Csg
9 ⅝” Csg
TD
18 ⅝” C.P.
3 Jts
18 ⅝” Csg
9 ⅝” Csg
TD

2. Preparations and Off-Line Operations

- Check and test MWD and LWD on surface
- Ensure that all 7'' liner accessories and back up are available, serviced and ready.
- Test cement unit and cement lines while running casing.
- check 7'' liner hanger assembly.
- Rig up power tong for running casing prior circulating at bottom.
- All casing running and cementing equipment to be services and checked prior running casing.

3. Cleaning 9 ⅝" Casing

- Run in hole with 8 ½" bit and BHA as applicable (see recommended BHAs below).
- Wash down last ±30-50' above plug, drillout cement and float equipment to 10 feet above float shoe with reduced parameters: 60 RPM, 8000 Lbs and maximum flow rate to clean hole from cement). Check manufacturers recommendations.
- Sweep hole with hi-vis pill and circulate hole clean whilst drilling out.
- Pressure test casing to a surface pressure of 60% of the minimum internal yield strength of the casing or to 2500 psi, whichever is lower for 10 min (test to 5000 psi in case of WAG or gas injection wells).

  Note:

  In case of unsatisfactory casing pressure test or requirement of cased hole logs:

  - Pull out of hole.
  - Run in hole with 8 ½" bit without jets and 9 ⅝" casing scraper.
  - Run logs and/or casing test packer, and locate failure depth.
  - Take corrective measures until satisfactory test is obtained.

4. Drilling 8 ½” Hole

- Run with 8 ½“ directional BHA according to tables specified under 4.2 (Recommended 8 ½” drilling assemblies).
- Drill float collar, cement, float shoe and 10 ft formation, (if cement is soft in shoe track, then don’t drill out shoe and report to town).
- Displace hole to new mud while drilling and conduct shoe bond test at pressure gradient equivalent to 0.65 psi/ft. Report injectivity if any.
- Continue drilling 8 ½“ hole to 7” casing point as per directional program
- Gyro keeper will be required to orient tool face and kick off; run Gyro, drill 100’ vertical below shoe and kick off with MWD.
- Use RSS when economically justified as per requirements.
- Circulate hole clean with high viscosity pill to agitate the cuttings beds. This should be followed with high weight pill. Circulate hole at high rate with rotation until shakers are clean, refer to Chapter-4 “Drilling optimization” of this Volume.
- Wiper trip the hole as required.
- LWD is required to drill this section; LWD tool (with stabilizer) is run with directional assembly. Wipe logging might be requested to get better quality density log, this normally done while pulling out of hole at $\pm$ 700 ft/hr.
- The following logging is generally required in 8 ½“ directional hole:
    - LWD (Resistivity, Density, Neutron, GR)
- Geological modeling is required in critical wells to ensure smooth trajectory for drilling and running casing and also to avoid penetrating the zones below or above the zone of interest.
- Pull out of hole for 7” liner, wipe logging if necessary.
- On the last trip out of the hole with drill pipe, with the bit at the casing shoe, set slips and rotate the work string 10 and 20 rpm and record the torque.
- Drop hollow drift, POH and lay down BHA.
- If the achieved BUR is above the plan, rotate drill string to reduce it. Do not reduce BUR by intentionally sliding with the tool face orientating to the right side and then to the left side (a practice known as “Wig-Wagging”).
- Slides with the tool to one side to correct azimuth are acceptable but should be kept to minimum. If rotation is not possible due to equipment limitations / bent housing configuration then trip as necessary to change the bent housing to achieve the required BUR.

4.1 Drill String and BHA Design Considerations

- BHA's to be discussed and agreed with directional drilling company prior RIH.
- All stabilizers shall be gauged prior to use. Undergauge stabilizers shall be changed out except when required for directional purposes. When utilizing undergauge stabilizers, ensure sufficient carbide dressing thickness remains on the stabilizer to protect the stabilizer from excessive wear. All stabilizers should be well tapered both top and bottom.
- Optimize jarring system and placements. Get jar manufacturer to run optimization programme and advise for BHA's proposed, refer to Volume-2, Chapter-2 "Special Drilling Operations.
- BHA lateral vibration / whirl is a major cause of downhole tool failures. Unstabilised tools are particularly susceptible to lateral vibration in vertical or near vertical hole sections. A vibration and buckling analysis should be undertaken when planning BHA's.
- A correctly rated shock sub or a thruster should be considered if vibration levels cannot be controlled. If a thruster is used, the correct set up of the tool is to be planned.

4.2 Recommended 8 ½" Drilling Assembly.

4.2.1 Option 1 (Directional Drilling)

To be used when build up rate is > 10º/100 ft.

Table 2-34: Recommended BHA for drilling 8 ½" Directional Hole (1)

Size	Description	No.	Comments
8 ½"	Tricone Bit	1	
6.3/4"	Motor	1	
6.3/4"	N.M. Drill Collar	1	
6.3/4"	Hang off Sub	1	
6.1/2"	Orient Sub	1	
6.5/8"	N.M. Drill collar	1	
6.3/4"	MWD/LWD	1	
5"	Drill pipe		Number depends on the length of departure
5"	HWDP	30	
6.1/2"	Drilling Jar	1	
5"	HWDP	12	
5"	Crossover	1	

4.2.2 Option 2 (Directional Drilling)

To be used when build up rate is < 10º/100 ft.

Table 2- 35: Recommended BHA for Drilling 8 ½” Directional Hole (2)

Size	Description	No.	Comments
8 ½”	PDC Bit	1	
6.3/4”	RSS	1	
6.3/4”	MWD/LWD	1	
8 ½”	S. Stab	1	
6.1/2”	Drill collar	1	
8 ½”	S. Stab	1	
6.1/2”	Drill collar	1	
5”	Drill Pipe		As many as required for departure
5”	HWDP	30	
6.1/2”	Drilling Jar	1	
5”	HWDP	12	
5”	Crossover	1	

4.2.3 Option 3 (Vertical Drilling)

To be used when pilot hole is required for open hole logging or when required for gas wells.

Table 2- 36: Recommended BHA for Drilling 8 ½” Vertical Hole

Size	Description	No.	Comments
8 ½”	PDC Bit	1	
6 ¾”	Motor	1	
8 ¼”	S. Stab	1	
6 ½”	Drill collar	1	
8 ¼”	S. Stab	1	
6 ½”	Drill collar	12	
6 ½”	Drilling Jar	1	
6 ½”	Drill collar	3	
5”	HWDP	12	
5”	Cross Over	1	

Changes may be made to the above recommended BHA’s depending on the hole trajectory, target and hole condition.

4.3 Directional and Geological Challenges

The following table highlights the directional challenges that can be encountered while drilling 8 ½” hole.

Table 2- 37: Directional Challenges for 8 ½” Hole

Formation	Directional Issues
Shilaif	• Hard formation. Difficult to kick off. Sliding slowly to build up angle. • Common bit damage due to high compressive strength of the formation.

Formation	Directional Issues
Mauddud	• Thin section of shale and medium hard limestone.
Nahr Umr	• Shale sloughing and hole cleaning problem. • Overgauge hole. • Drop tendency towards middle of formation. • Unpredictable walk rate in rotary mode. • Poor bit performance due to damage sustained while drilling the Shilaif formation. • Avalanching of shale cuttings down word where hole pack-off could occur. • Kicking off in Nahr Umr, particularly from vertical, and maintaining BUR (in excess of 5 º/100 ft), can be a challenge. • The Nahr Umr Shale is time dependent to WBM and Polymer muds and becomes difficult to control after 7-10 days exposure. • The Nahr Umr Shale has also proven unstable at varying Hole Angles, although there are no apparent problems drilling the Nahr Umr vertically.
Shuaiba Units	• Weight transfer to the bit is difficult when sliding due to Dog leg, drillstring sticking due to differential pressure, mud cake and improper BHA configuration.
Thamama Zone	• Ledges while drilling streaks of soft and hard formation. • High differential pressure across reservoir especially when Thamama zones are drilled with high mud weight required to control Nahr Umr, this makes sliding difficult due to differential sticking.

5. Drilling Optimization

5.1 Bit Selection

The objective is one fast bit run, while achieving build objectives. Typically, motor steerable PDC bits are capable of completing the section in one run. It is essential that a PDC bit used in the build section incorporates technology to allow good toolface control. Typically, 5 or 6 bladed PDC bits are used, with cutter sizes ranging from 13 mm to 19 mm. Occasionally, on short sections, or where particular directional objectives need to be met, a tri-cone bit is used (IADC 517).

5.2 Hydraulics and Nozzles Selection

Targeted minimum flowrates for hole cleaning are generally easily achievable. Hydraulic optimization can focus on maximizing HSI. This is particularly important for the use of PDC bits in water based muds (especially for ROP through the Nahr Umr). It is recommended to aim for HSI > 3. Hydraulic should be calculated for every bit run. Well plan program (LandMark) is the program to be used for those calculations.

5.3 Hole Cleaning

- Pump rates aim for 500 gpm or higher.

- The above recommendations are very generic, and each application should be analysed accordingly. Factors influencing hole cleaning include: flow rate, annular cross-sectional area (drill pipe OD), mud rheology and mud weight, cuttings size, inclination, drill pipe rotational speed, length of sliding intervals (zero pipe rotation), drill pipe eccentricity, ROP. Refer to Chapter-4 “Drilling Optimization” of this volume.

5.4 Motor

- 6.3/4” (or similar), medium speed motors are standard.

- Motors must be run slick in build sections. Experience has shown this to be the best option. Experiments with various stabilized set-ups have failed due to weight transfer difficulties.

- Motor bend versus allowable rotation must be checked in high BUR trajectories.

- Hole spiraling is likely to occur when rotary drilling with a motor and bent housing. Bit whirl / off-centre rotation is induced by the action of rotating the bent housing. The higher the bend angle the more likely hole spiraling will occur. To overcome this problem a long gauge bit or turbo-back stabilizer can be used. Another method of reducing hole spiraling is to reduce the distance from bit face to bent housing.

- Refer to Chapter-2 “Special Drilling Operations” in Volume-2 for more details on Motor, RSS, MWD, LWD.

5.5 Drilling Parameters

- Avoid operating parameters that lead to drill string vibrations. Use a rotary speed that is high enough to give smooth rotation of the drill string, but not so high that axial and/or lateral drill string vibrations or bit whirl occur.

- Ledging can be an issue when drilling alternate hard and soft formations particularly at an angle. This can occur when drilling through the reservoir zones. Ledging occurs generally at the top of the harder formations at the interface when whirl or other lateral instability is induced due to the reduced depth of cut. This can be reduced or eliminated by following negative drill break practices and easing the bit into the harder formation.

- Poor weight transfer to the bit can also produce ledging and hole enlargement by reducing the depth of cut at the bit, thus initiating lateral instability and whirl.

- Ensure preventative drilling practices are strictly adhered to i.e. moving and rotating drill-string as much as possible, minimizing length of unstabilised BHA, use of spiral Drill Collars and HWDP. These measures however may not be practical in wells where the build to horizontal is a critical objective.

- Control of differential pressure places requires high quality filter cake and fluid loss when drilling the reservoir. There are several specialized “bridging“ products that reduce seepage thereby reducing the likelihood of differential sticking in permeable zones. Refer to Chapter-5 “Mud Guidelines” of this volume for more details.

- To reduce the likelihood of whirl being induced, correct start up procedures should be followed after each connection and negative drill break practices followed at significant hard rock interfaces. PDC bit whirl is more likely to occur in harder formations where cutter depth of cut is reduced.

6. Drilling Fluid

Refer to Chapter-5 “Mud Guidelines” of this volume for mud details.

7. Running, Setting and Cementing 7” Liner

7.1 Liner Equipment

7.1.1 Bullet Shoe

Run at bottom of the liner, and serve as both guide shoe and valve float assembly. The back pressure valve prohibits flow of fluid/cement into the liner when pumping stopped. All major internal components are constructed of drillable cast materials to allow simple drillout with PDC bits.

7.1.2 Float Collar

Typically run two joints above the shoe and prevent backflow of cement into the liner after displacement complete.

7.1.3 Landing Collar

Usually run one or two joints above float collar and provide the seat and latch profile to catch the liner wiper plug at the completion of cement displacement. Landing collar is designed to ensure rapid and complete drillout.

7.1.4 Ball Catcher

Installed bellow the landing collar and used to catch the shearout ball and setting ball used in a hydraulic liner hanger system. The perforated baffle plate is designed to catch the ball and seat, yet permit unrestricted fluid/cement circulation.

7.1.5 Hydraulic Set Liner Hanger

Conventional Type:

Conventional Liner Hanger is set hydraulically by applied pressure through the run-in string. The hanger is used in deep and high angle wells where actuation of mechanical set hanger is difficult. A ball is dropped to a seat in the landing collar, and differential pressure acts on the hydraulic cylinder, moving slips up the cones to set position.

Rotating Type:

The rotating Liner Hanger incorporate a tapered roller bearing assembly which allows the liner to be rotated with the hanger in the set position while circulating or cementing, resulting in improved cement job.

7.1.6 Drillable Pack-off Bushing

The Pack-Off Bushing is designed to provide seal at the top between the setting tool and liner ID.

7.1.7 Setting Sleeve with 6 ft Tie-back Extension

The Liner Setting Sleeve consists of a body with a left-hand box thread into which the float nut of the setting tool is engaged, combined with a tieback extension. After reaching setting depth, the setting tool is released with right-hand rotation of the running string.

7.1.8 Cement Dropping Head

The Cement Dropping Head is attached to the top joint of the liner running string to allow the pump down plug to be released from surface without breaking a connection or hammer union.

A heavy duty swivel is included at the lower end to allow reliable rotation of the running string.

The pump down plug is held above a screw-operated ram in the main body of the head. An external manifold with two full-opening plug valves direct the flow of mud and cement below or above the pump down plug as required

7.1.9 Flag Sub

Placed immediately below the plug dropping head and provides immediate visual confirmation that the plug has been dropped.

7.2 Preparation Prior to Running Liner

- Insure all tools, accessories and supplies are at rig site and verity using printed check list.
- Measure the OD's, ID's and lengths of all liner equipment and setting tools then prepare a fully detailed drawing prior to job.
- The setting tool to be checked visually and by measurement to be sure that it's the modified tool designed for ADCO and the correct size. The bottom nose of slick joint OD should be 1/16" less than the body of slick stinger.
- Check that the pump down plug is suitable for drill pipe in use will pass through reversing tool and X-Overs and that it is the correct size for the liner wiper plug.
- Check that the landing collar is the correct size for the liner wiper plug. Check that correct numbers of shear pins are installed in the liner wiper plug holder.
- Make-up liner hanger assembly on pipe rack.
- Make-up the setting tool and 5-10' long 5" drill pipe pup joint above. Make connection with a 48" chain tong. Check 2.3/8" drift will pass setting tool.
- Stand liner hanger assembly against rig floor and carefully lower setting tool into tie-back sleeve.
- Make-up the setting nut by rotating the setting tool to the left. Back out 1-2 turns and then make up again by bumping up the connection with a 36" chain tong. Paint a line across the top of the tie-back sleeve onto the setting tool to ensure that this connection does not loosen or tighten during making up in the table.
- Stand back the liner hanger assembly in a safe place and leave it secured until required.
- Install the drill pipe wiper plug in the plug dropping head after ensuring correct operation of the valves and screwing in the plug retaining pin. Open the lower circulating valve, close the upper circulating valve and finally check the correct chicksan connection is ready on the rig floor.

- Install centralizers as per simulator programme to achieve 80% stand-off based on actual hole trajectory and run scratchers across critical intervals.

7.3 Liner Centralization

The centralization purpose is to facilitate running casing to the desired depth and to assist in centering the casing in the borehole while cementing.

In high deviated and horizontal wells, good casing standoff is one of the most important factors in preventing mud pocket formation and achieving the required zone isolation.

The centralization programme should also focus on reducing torque and drag required for liner movement (reciprocation and rotation) and help creating fluid turbulence in annulus to remove cutting beds on the low side of wellbores and promote uniform cement bounding.

7.3.1 Types of Centralizers

(1) ***Flexible Centralizer (Bow Type):*** Consists of flexible springs attached to two collars. The outer diameter of a bow type centralizer is normally larger than the well diameter. Due to this configuration, they can centralize the pipes in washout areas as well as in undergauge holes.

(2) ***Centralizers with Fixed Outer Diameter (Rigid Type):*** They can either be made of non-flexible fins attached to two collars or a single solid piece with a fixed outer diameter. This type of centralizers is typically used when drag forces have to be minimized especially in order to run long horizontal liner to TD and also to create fluid turbulence.

7.3.2 Centralizer Selection Criteria

Table 2- 38: 7" Liner Centralizer Selection Criteria

Application	Bow Type		Rigid Type	
	Non-Weld	STT-I-SL	Solid Body	SpiraGlider
Rotating liner applications	Not to be used	Excellent	Good	Excellent
Drag force minimization required	Not optimized	Excellent	Good	Excellent
High build-up rate	Good	Good	Not to be used	Good
Passing restrictions in the wellbore	Good	Good	Can not be used	Can pass restrictions without being damaged

Application	Bow Type		Rigid Type	
	Non-Weld	STT-I-SL	Solid Body	SpiraGlider
Hydrodynamics	Not optimized	Good	Good	Optimized (large flowby area)
Passing casing windows	With caution (danger of hang-up)	Good	With caution (danger of hang-up/destruction)	Good
Gauge hole	Excellent	Excellent	Excellent	Excellent
Slightly oversized hole	Excellent	Excellent	Good	Good
Large washout section	Excellent	Good	Not to be used	Not to be used
Under gauged hole	Good	Good	Can not be used	Should not be used

7.4 Typical 7” Liner Configuration:

- 7” Bullet shoe
- 2 joints 7” casing
- 7” float collar
- One or two joint 7” casing
- 7” landing collar
- 7” casing to provide 300 ft overlap in 9 ⅝” casing
- Marker joint positioned at top of reservoir
- 7” hydraulic set liner hanger (conventional or rotating)
- Drillable pack-off bushing
- Setting sleeve with 6 ft tie-back extension

7.5 General Guidelines for Running 7” Liner

- Liner hanger operator to be on site for running all times.
- No scraper run is required to set liner hanger.
- Pick up and run in hole with shoe joint (bullet shoe should be used if available, otherwise grind the fins on the shoe), fill up and flow check floats. Run shoe track threadlocking connections. Make up landing collar.

- Continuously monitor annulus for mud returns while RIH, fill liner every 5 joints.

- Change to Drill Pipe elevators and pick up liner hanger assembly. Make up to liner. Set slips on the running tool pup joint, install circulating head, and pick up out of slips.

  DO NOT AT ANY TIME SET SLIPS ON LINER TIEBACK SLEEVE.

- With liner tieback sleeve above rotary table, fill sleeve with Gel Mud, circulate liner volume at a maximum of 900 psi. Check for leaks up through the tieback sleeve. Record liner pick up weight, slack off weight and torque.

- Record liner pick up weight and slack off weight.

- Run in hole with Liner. Do not run faster than 45 second per stand inside casing and 60 seconds in open hole. Ensure rotary table is locked and back-up tong is used when making connections.

- Before entering open hole, circulate liner capacity at a maximum of 900 psi, record flow rate and toreque.

- Install the cementing manifold with the pump-down plug in the plug-dropping head on a single joint of DP in the mousehole while circulating. Lay this complete assembly aside where it can be easily accessible. Rig up all cementing and circulation lines and enough sections of chicksan pipe to wash down whenever necessary.

- Continue running in hole with liner until it reaches bottom.

- If down drag increases more than 20,000 lbs or the liner is held up at any depth while RIH, stop and circulate. (Don't push the liner down). Begin circulating slowly at 5-8 BPM to break gelled mud while reciprocating liner continuously. Increase BPM when the pressure, drag up and drag down stabilize. Do not exceed 900 psi to prevent liner hanger setting in case the hole packs-off completely. When free and bottoms up is complete, continue RIH to bottom.

  Note:

  In case of rotating Liner Hanger: Enter open hole and run liner slowly down to bottom, liner can be rotated if required. Pick up plug dropping head rotating assembly. Circulate slowly and lower pipe slowly to tag bottom.

- If the liner shoe does not reach the required depth due to caving shale and poor hole condition, the liner must be pulled out of the hole and a wiper trip made. Use special care not to get the liner stuck off bottom.

- Make-up the landing joint with cementing manifold, ball releasing sub and swivel on top of setting string. Wash down the last joint to bottom.

- When liner is at TD, start circulating at 6-8 BPM to break up gelled mud. After pump pressure is stable for 10 minutes begin reciprocating liner 12' to 15' at 1 stand per minute to help remove any cuttings, shale and excess filter cake from the hole.

- When drag up / drag down and pump pressures are stable for 10 minutes, begin circulating at 11-12 BPM while continuously reciprocating liner. Increase pump pressure slowly to avoid surging the hole.

- When drag up/drag down and pump pressure are stable again, slowly increase circulation rate to 17-18 BPM while continuing to reciprocate liner to ensure the hole is perfectly clean before pumping cement. Hole should be circulated until shale shaker is clean, plus at least two cycles.

7.6 Setting Conventional 7” Liner Hanger

Set liner hanger and release setting tool prior cementing job as follows:

- Drop the setting ball and circulate ball down slowly. When the ball seats in the shear seat of the landing collar, pressure up on same.
- Increase pressure slowly to 1500 psi and gradually to 2000 psi, you will notice a minute decrease in pressure, this will indicate that the shear pins in the hydro-hanger setting sleeve have sheared, setting the hydro-hanger.
- Hold pressure constant, slack off on the setting string until the weight of the liner is setting on the hydro-hanger slips. Continue to slack off until approximately 10,000 lb of setting string weight is applied.
- Increase pump pressure until the ball seat in the landing collar shear out (2500-3500 psi). This will be indicated by regaining circulation.
- Re-establish circulation rate that you will need to maintain while cementing (12-14 BPM).
- To release from the liner, stop circulating and release pressure.
- Land setting string on slips and rotate setting string to the right for 6 or 8 turns, check for torque, continue to rotate to right until 24 torque free turns are obtained.

- Raise the setting string approximately 3 ft, note loss of liner weight. Lower the setting string until 10,000 lb of setting string weight is resting on the liner.

7.7 Cementing Conventional 7” Liner

- Cement volume to be calculated with 35% excess on the caliper volume for the open hole or 40% excess on O. H. volume if caliper log is not available. Plus the liner-casing annulus with 10% excess volume plus 200' above T.O.L in addition to shoe track (L.C and Shoe).

- All the openhole should be covered with tail slurry plus 40% excess.

- Meeting to be held with all concerned parties to discuss the cement job while circulating liner. Calculate spacer volume, cement volume and displacement volume. Assign job responsibilities for each individual.

- Test cement lines against valve on plug-dropping head to 5000 psi for 5 minutes.

- Pump 150 Bbls L .V. mud at 17-18 BPM followed by 20 Bbls un-weighted spacer and 40 Bbls weighted spacer (90 pcf) while mixing cement in batch tank mixer (Cement spacer recipes as per Lab formulations).

- Pump the calculated cement slurry of 118 pcf (lead) and 125 pcf (tail) mud weights at the highest possible rate (Cement recipe as specified in the drilling program). While pumping the cement, batch mixing tank to be monitored visually to be sure that all cement is pumped before releasing the pump down-plug and displacing the cement.

- Release the pump-down plug after ensuring all cement is pumped. Displace cement with FRESH WATER and followed by mud as detailed in cement program using cement unit. Displace cement at (12-14 BPM). Displacing cement in turbulent flow is the best flow regime to maximize mud removal and ensure the cement slurry is placed completely around the liner. Use calibrated tank for keeping and pumping displacement fluid.

- Reduce pump rate to 2 BPM at 10 Bbls before the pump down plug reaches the liner wiper plug. As soon as plug shears, immediately increase pumping rate to 12-14 BPM.

- The amount of displacement pumped should be checked at this time to confirm DP volume in order to continue with liner volume displacement.

- Continue pumping at 10-12 BPM and bump plug at 3000 psi. (Do not over-displace pump only theoretical volume).

- When no losses are encountered during circulation or cement job and it is not expected to initiate losses by reversing out at TOL , sting out and reverse out circulation just at TOL twice string capacity. Otherwise POH 10 stands above TOL, and then reverse circulate twice string volume with press not exceeding 500 psi.

7.8 Setting Rotating 7” Liner Hanger

- At TD, Hole should be circulated with increased rates until shale shaker is clean, plus at least two cycles.
- Pick up liner to setting depth and mark pipe.
- Drop setting ball and circulate down to seat, lower circulating rate prior to ball landing on seat.
- Pressure up to 1600 PSI to activate hanger slips.
- Slack off liner weight + 20,000 lbs. Note that the hanger is set by liner taking weight off bottom.
- With 20,000 lbs set down on hanger, increase pressure to 2400 PSI to release running tool.
- When picking up on drill string to ensure the setting tool is released, do not exceed recommended pickup distance (extension length minus two feet). If this pickup distance is exceeded, the packer setting dogs may be pulled out of the setting sleeve and set down weight of the run-in string may pre-maturely set the packer seals and slips (if integrated top packer is used).
- Slack off 20,000 lbs. and pressure up to 3000 psi to shear out ball seat.
- Start rotating liner increasing to 15 rpm - 20 rpm. TAKE CARE THAT TORQUE DOES NOT EXCEED PREDETERMINED MAXIMUM ALLOWED TORQUE VALUE. See Rotation Test formula bellow. Set torque limiter to just above rotating amps, so the table will stall out without damaging equipment.
- Rotate while circulating to clean the hole (as require). Then brake out the top drive and pick up the cement manifold, tested to 5000 psi.
- Set the slips / cement Kelly and rotate the rotary to check the torque again at 10 RPM and 20 RPM before the cement job.

7.9 Cementing Rotating 7” Liner

- Perform cement job as per cementing program.
- Use same procedure and volumes as in Conventional Liner.
- Release drill pipe wiper plug, and pump plug down hole. Slow down to 2 bbl/min. 5 bbl. before latching liner wiper plug.

- Slow down to 2 bbl/min 10 bbl. before bumping plugs.
- Bump plugs and pressure up to final test pressure.
- When the cement job is complete, the run in string is raised positioning the setting tool above the top of the setting sleeve allowing the packer setting dogs to become exposed. Spring force will extend the setting dogs. The setting tool is then lowered and the packer setting dogs locate on top of the packer tieback extension. Drill pipe weight is slowly added to the top of the liner (Normally 60,000 Lbs). The first shear will initiate the setting of the expanding metal element. If the Packer is equipped with hold down slips, a second shear will set the hold down slips in the casing ID. Minimum set down weight should be maintained on the liner top for 2-3 minutes to allow the element to stabilize after setting.

  (This step is not required if No packer is run with the liner)

- Pull up 2 to 3 ft. and circulate or reverse circulate as required (reverse circulate if a packer is run with the liner OR pull above top of cement and circulate if no packer is run with the liner).
- Pull out of hole and lay down setting tool.

  NOTE:

  If after completing “Setting Rotating 7” Liner Hanger”, setting tool is not released, ensure that 15,000 lbs. set down weight is on running tool, continue to pressure up to blow out ball seat in landing collar, bleed pressure to zero, apply left hand torque (1/4 turn at setting tool) to mechanically release running tool from hanger. After screws have sheared the body of the setting tool will turn ¼ turn and drop down 1-3/4 inches. Pick straight up with work string to release collet from the profile in Setting Sleeve.

7.10 Rotation Test

This test must be performed on the last trip out of the hole with drill pipe, with the bit at the casing shoe, set slips and rotate the work string 10 and 20 RPM and record the torque.

Cased hole torque (A) =__________ft-lbs @ 10 rpm. Or 20 rpm.
Liner thread torque (B) =__________ft-lbs [Optimum Torque]
Maximum allowable Surface torque (C) = A + (B x 80%) = _________ft-lbs
One rotary Amp. (D) =__________ft-lbs. torque
Maximum allowable Rotary amps (E) =C divided by D =_________Amps

7.11 Cement Quality Parameters (CQP)

These parameters have to be fully satisfied prior and during cement job.

Table 2- 39: Cementing Quality Parameters (CQP)

Item	Cementing Quality Parameters
1	Hole circulated adequately prior to job
2	Conducted reciprocation while circulating hole and while pumping conditioned mud or rotation during all job
3	Mud conditioned prior to job
4	Casing centralized properly
5	No mechanical failure of the liner or float equipment
6	Used suitable and adequate cement spacer
7	Used cement slurry of suitable properties and adequate volume
8	Hole stable during job (no losses or flow, no abnormal pressure or hole pack-off)
9	Cement displacement rate as per program
10	Pumped only theoretical displacement volume (no over-displacement)
11	Found cement at TOL or had cement to surface while reversing out
12	Tagged hard cement within shoe track

8. Drilling Hazards

Table 2-40: Hole Drilling Hazards in 8 ½"

Potential Hazard	How to Mitigate
Stuck Pipe	• The mud weight must ensure stability within the Nahr Umr Shale and minimize the risk of differentially sticking when crossing the zones within the reservoir objective. • Installing string stabilizers within the drillstring to ensure 'stand-off' from the wellbore in permeable reservoir formations will compromise directional (build) capability. • Use of Rotary Steerable Systems will minimize overall contact with the wellbore and will reduce the tendency for differential sticking, particularly in longer extended reach wells. • The possibility of differentially stuck pipe remains across these intervals because any lower mud weight may compromise the stability of the Nahr Umr Shale sequence – particularly if drilled at an angle. • Ensure preventative drilling practices are strictly adhered to i.e. moving and rotating drill-string as much as possible, minimizing length of unstabilised BHA, use of spiral Drill Collars and HWDP. These measures however may not be practical in wells where the build to horizontal is a critical objective.
Well Control	• Most of well control problems occur while tripping out due to swabbing (tripping speed) or failure to fill the hole with proper fluid volume; trip sheet has to be filled accurately and control tripping out speed to avoid well control problems. Refer to "Well Control Chapter for more details".

9. Equipment Required

9.1 Casing Accessories Equipment

Table 2- 41: 7" Liner Casing and Accessories

S. N.	Description	Grade	Wt lb/ft	Thread	MESC No.
1	Casing, R3	L-80	29	NK3SB	04-12-88-225-9
2	Casing Pup (5')	L-80	29	NK3SB	04-12-89-105-9
3	Casing Pup (10')	L-80	29	NK3SB	04-12-89-110-9
4	Casing Pup (20')	L-80	29	NK3SB	04-12-89-120-9
5	Auto fill float collar	L-80	26-32	NK3SB	05-14-26-270-9
6	Liner Hanger	L-80	29	NK3SB	05-29-06-182-9
7	Liner Hanger	L-80	29	NK3SB	05-29-25-146-9
8	O.H. Centralizer Spiraglider W/Stop collar	-	-	-	05-17-25-036-9
9	O.H. Centralizer	-	-	-	05-17-25-104-9
10	+ve Centralizer	-	-	-	05-17-30-106-1
11	Scratcher	-	-	-	05-17-15-016-9
12	Stop Collar	-	-	-	05-17-55-095-1
13	O.H. Centraliser Spirolizer.	-	-	-	05-17-25-636-9
14	Stop collar/ Spirolock	-	-	-	05-17-50-636-09
15	Casing Dope	-	-	-	87.47.25.07.09
16	Thread Compound	-	-	-	87.42.47.24.09

9.2 Dimensions and Mechanical Properties for 7" Casing

Table 2- 42: 7" Casing Properties

Properties	Values
Body OD (In)	7"
Grade	L-80
Weight (lb/ft) with collar	29
Connection	Premium
Min. ID (In)	6.184
Drift diameter (In)	6.059
OD of coupling (In)	7.656
Capacity (Bbls/ft)	0.0371
Body yield strength (klb)	676
Coupling yield strength BTC (klb)	746 (725 for N VAM)
Collapse pressure (psi)	7020
Burst pressure (psi)	8160
Make up torque optimum (ft.lb)	9700

10. Blowout Preventer

- No change is brought to the BOP in this section; same BOP configuration of the 17 ½” and 12 ¼“ hole is used.
- BOP’s should be tested when 14 days from previous test is reached.
- Refer to Chapter-3 “Well Control” Chapter for more details on BOP classification, installation and test.

11. Waste Management

Hole Size	Mud Salinity	Rental Equipment		Mud Handling	Cuttings Handling
8 ½"	Oil Base Mud	Air Pumps	1	**NO DUMPING** Mud to be stored for either recycling or to be transferred to injection disposal well	Cuttings to be drayed using H"G" dryer and transferred to cutting treatment plant into sealed cutting boxes.
		Auger	1		
		Tanks	4		
		Centrifuge	1		
	Water Base Mud	Tanks	4	**NO DUMPING** Excess mud to be transported to injection disposal well.	Cuttings to be piled on location and to be used to bund the location.

- No waste pit to be dug, use instead a 300 bbls tank to collect waste mud and then transfer to waste tanks.
- Environment inspection checks list to be filled at least weekly and sent to office.
- Ensure discharge from sewage treatment unit meets ADNOC regulations.

Notes:

1) Ensure all OBM cutting boxes are not damaged.

2) Fill only 3/4 capacity of OBM cutting box.

3) Ensure minimum solid content of the OBM cutting in boxes are 70%.

4) Ensure all boxes are covered on trucks by Tarpaulin.

6” OPENHOLE

1. Applications

The 6” hole is typically drilled horizontally to access Shuaiba units or Thamama zones, and is usually left openhole; the horizontal departure ranges from 1500 ft to 5000 ft.

Figure 2-38 shows the various 6’’ hole scenarios in ADCO.

2. Cleaning 9 ⅝” Casing

- Run in hole with 8 ½” milltooth bit and slick BHA to top of cement inside 9 ⅝” casing.
- Precautionary drillout cement to top of 7” liner with reduced parameters (60 RPM max, 8000 lbs) and maximum flow rate.
- Circulate hole clean and displace hole to Non-Dispersed Fluid (NDF) with maximum flow rate (see Chapter-5 “Mud Guidelines” in this volume).
- Pull out of hole and lay down all BHA including 5” HWDP and excess 5” DP.

3. Cleaning 7” Liner and Drilling 6” Hole

Cleaning 7” liner and drilling 6” hole are combined in one operation as follows.

- Make up and run in hole with 6” directional BHA (see recommended BHAs), picking up enough 4 ¾“ drill collars, 3 ½” HWDP and 3 ½” drillpipe to complete drilling the entire horizontal section (ensure 5” drillpipe will not reach TOL at the end of the 6” section).
- Run carefully through liner hanger and drillout pack-off bushing (workout string up and down across TOL several times).
- Continue run in hole to tag plugs. Drillout plugs, landing collar, float collar, cement to 5 ft above float shoe.

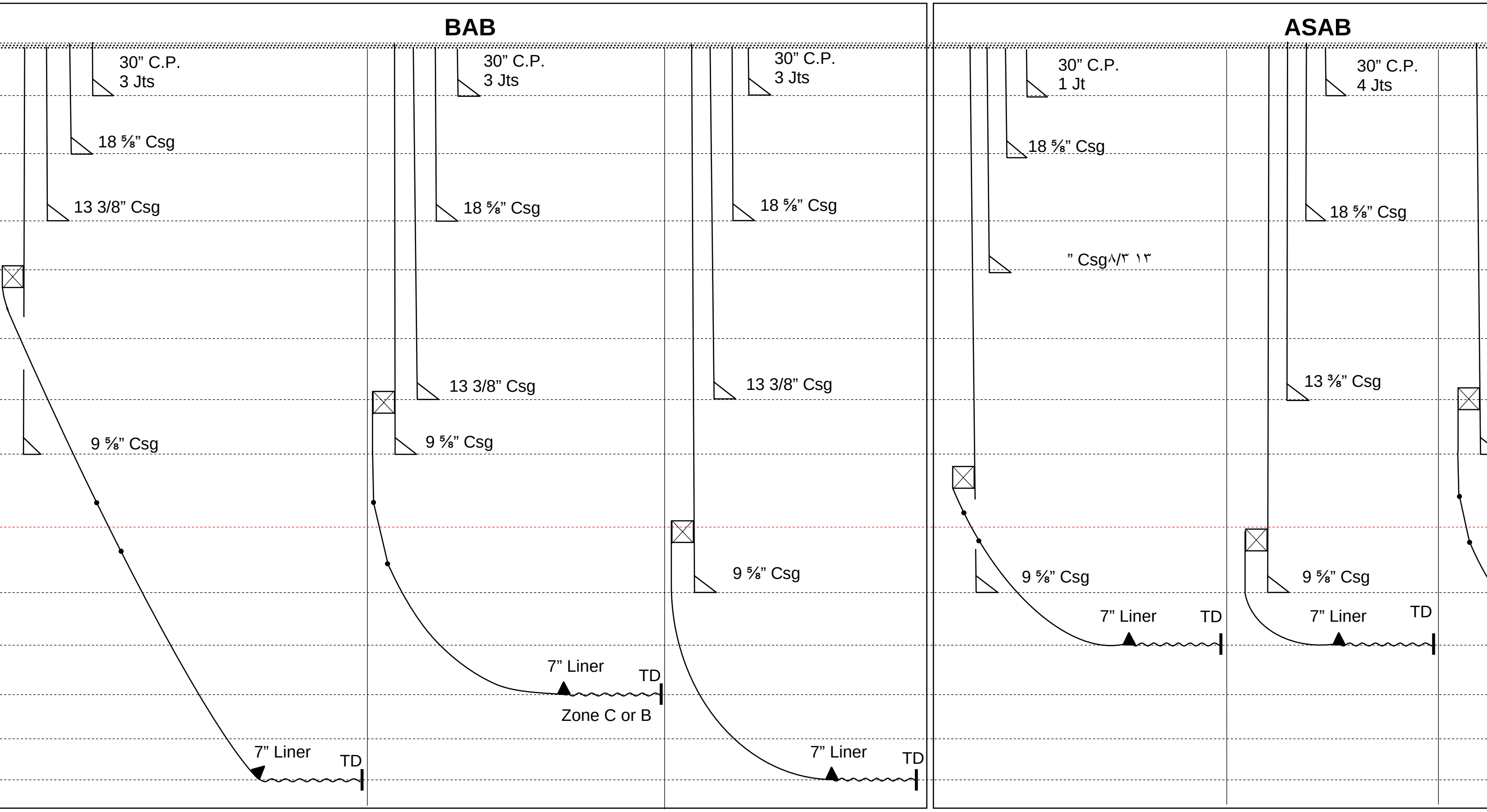
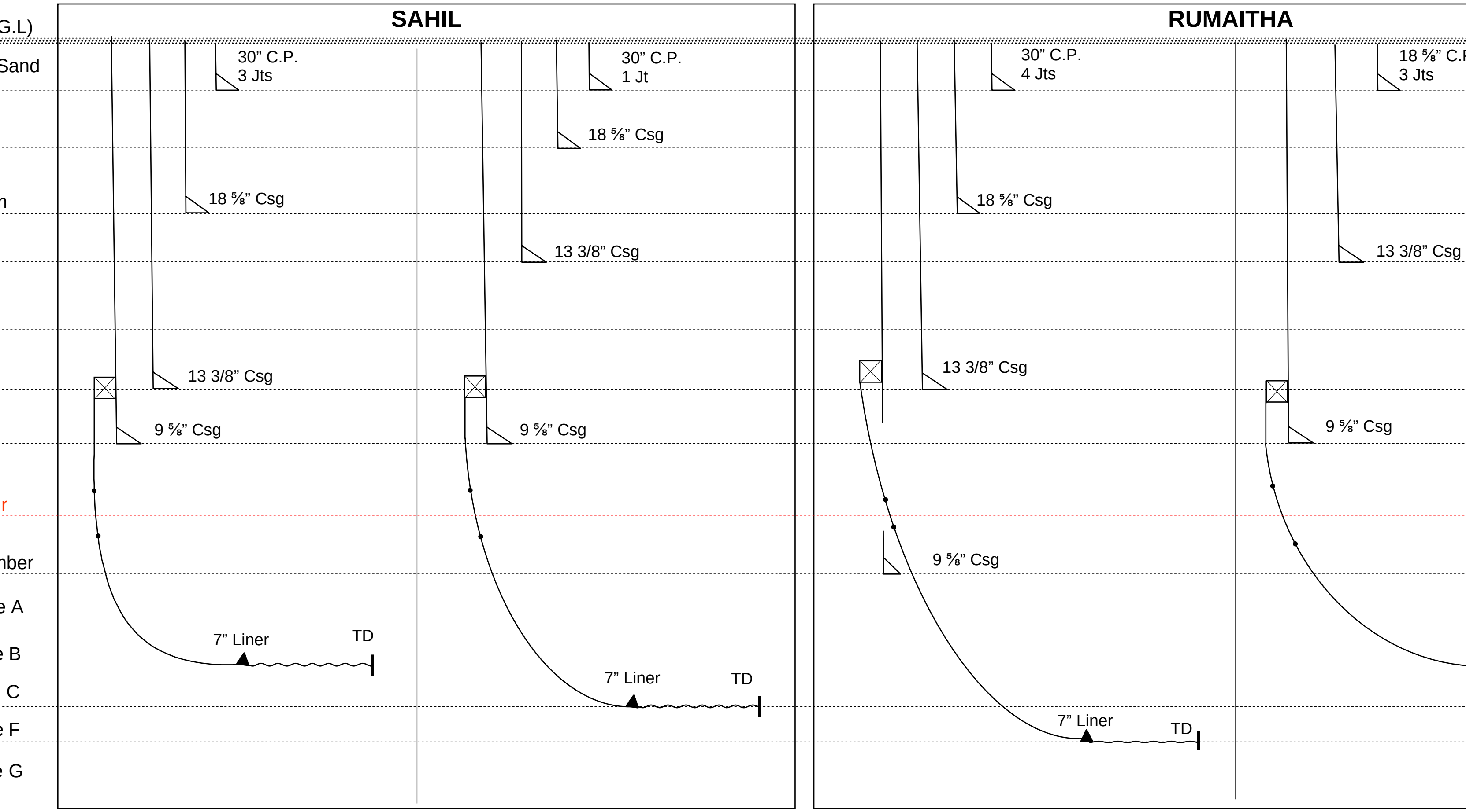


Figure 2-38: ADCO’s Typical 6” Hole



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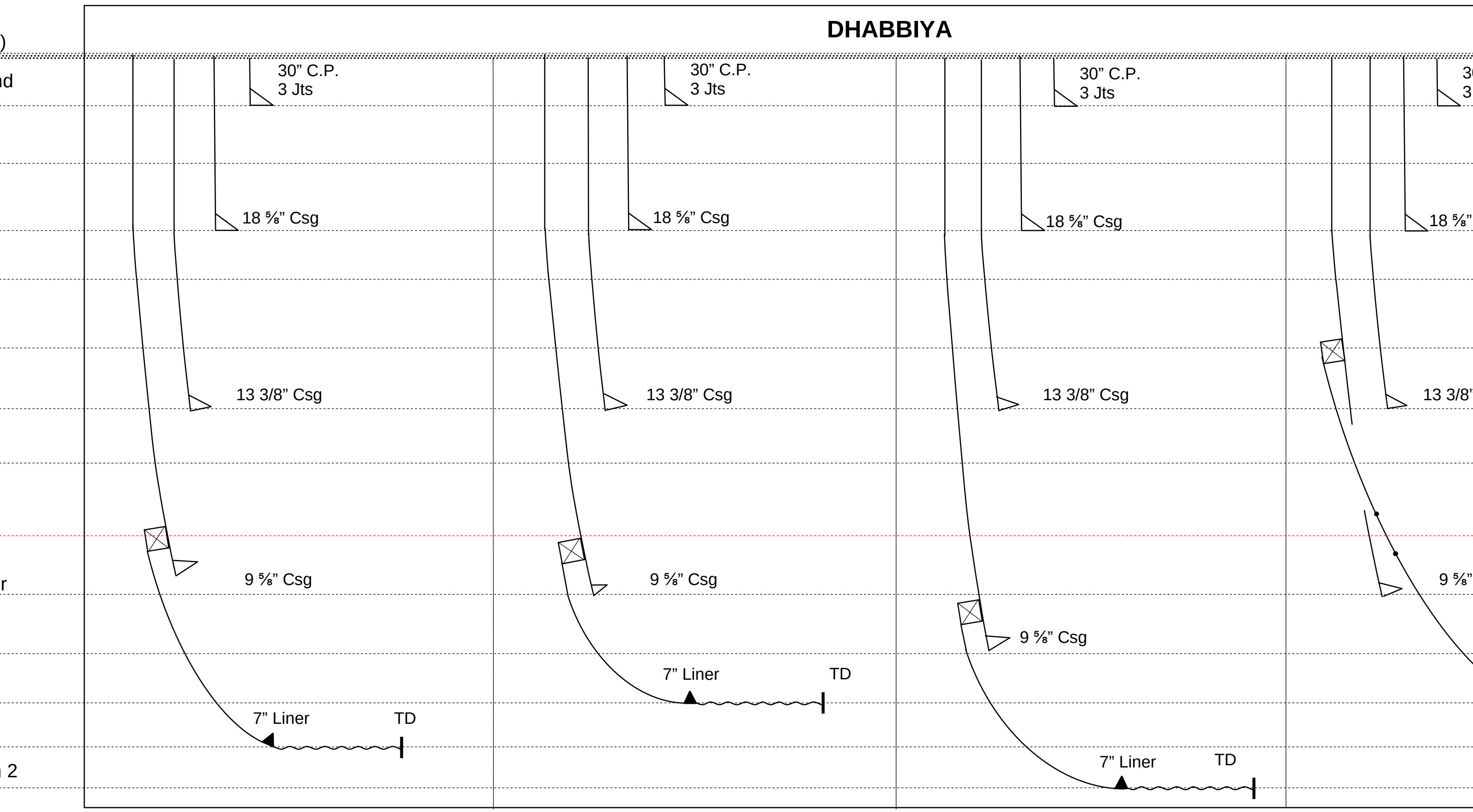
9 ⅝” Csg
7” Liner
TD
30” C.P.
1 Jt
18 ⅝” Csg
13 3/8” Csg
9 ⅝” Csg
7” Liner
TD
30” C.P.
4 Jts
18 ⅝” Csg
13 3/8” Csg
9 ⅝” Csg
7” Liner
TD
18 ⅝” C.P
3 Jts
13 3/8” Csg
9 ⅝” Csg



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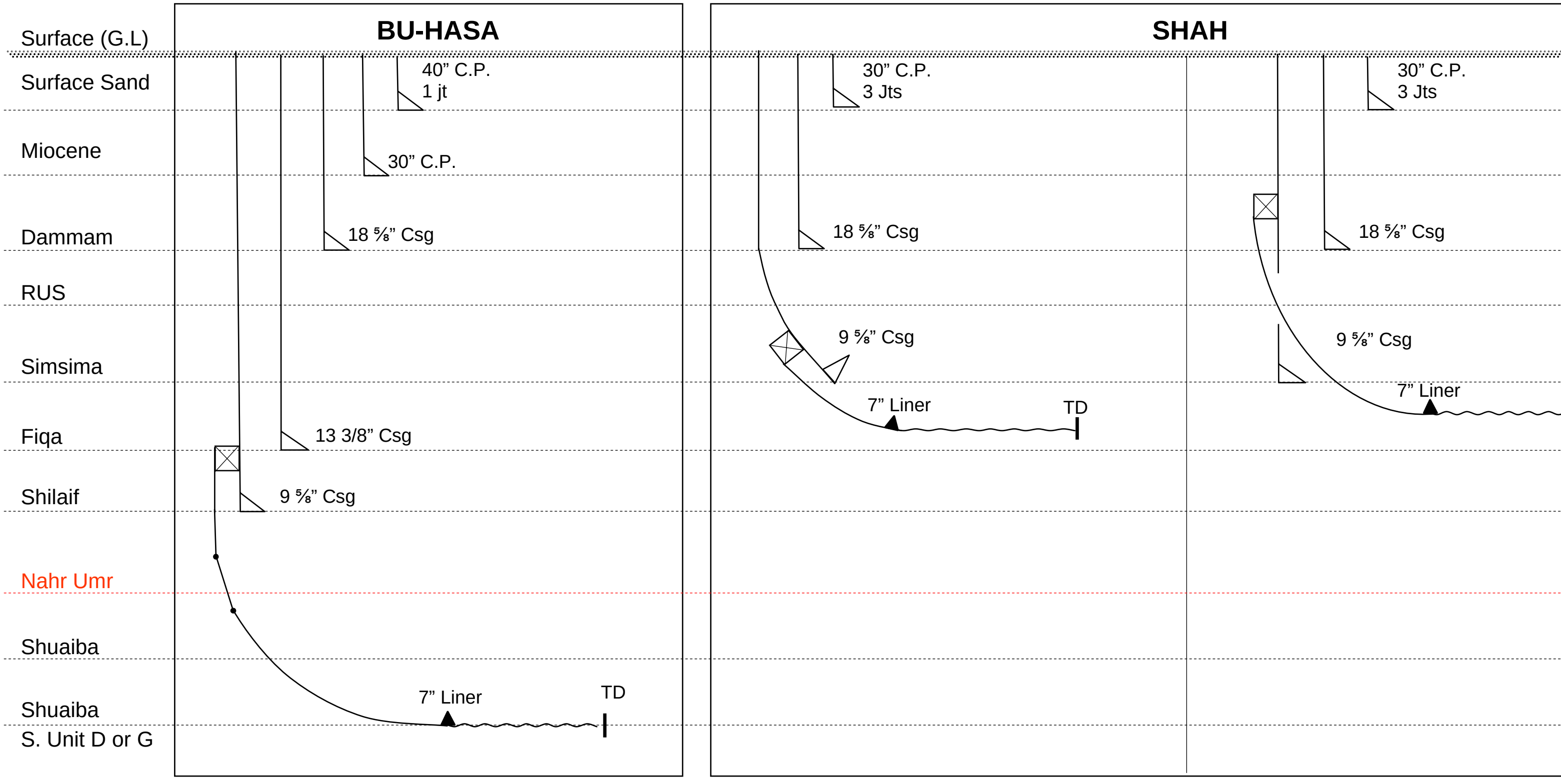
BU-HASA
SHAH
Surface (G.L)
Surface Sand
Miocene
Dammam
RUS
Simsima
Fiqa
Shilaif
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Shuaiba
Shuaiba
S. Unit D or G
40” C.P.
1 jt
30” C.P.
18 ⅝” Csg
13 3/8” Csg
9 ⅝” Csg
7” Liner
TD
30” C.P.
3 Jts
18 ⅝” Csg
9 ⅝” Csg
7” Liner
TD
30” C.P.
3 Jts
18 ⅝” Csg
9 ⅝” Csg
7” Liner

- Drill float shoe and 10 ft formation.
- Conduct Shoe Bond Test to 0.65 psi/ft for 10 minutes.

  Note: If plug did not bumped during 7” liner cementing; casing must be tested to 2500 psi for 10 min, if test is unsatisfactory, then remedial action is needed to ensure TOL integrity and zonal isolation.

- Drill 6’’ horizontal hole to total depth.
- Optimize drilling parameters. Circulate hole clean. Chapter-4 “Drilling Optimization” of this volume.
- Pull out inside casing shoe (wipe log if required).
- Perform final check trip and ensure having good accessibility to TD.
- Run 7” scraper and 9 ⅝” scraper in tandem to cleanout 7” liner and 9 ⅝” casing.
- If Cement Quality Parameters (CQP) are NOT FULLY SATISFIED (see CQP table in 8 ½“ hole section), record USI/CBL/VDL/GR/Gyro logs and ensure of good isolation at the TOL and between Thamama sub-zones prior drilling out 6” horizontal hole (minimum of 20 ft of good cement bound isolation is required).
- Conduct TLC logs (if required).
- Record cement bond log on tractor tool if needed.
- Run TCP guns with string mill, perforate zone of interest (in case of dual completion).
- Dress out and wash down perforations.
- Displace hole to completion fluid.
- Pull out of hole and lay down BHA.
- **Note:** To ensure smooth trajectory across required zone and to avoid penetrating different zones on critical wells, simulate the well trajectory using the Wellplan model before and after drilling the phase.

3.1 BHA Design Considerations

- A motor assembly or RSS assembly will be run to drill this section.
- Bit and nozzle details will be specified in the well program.
- Configure BHA’s to be as short and light as possible. Minimize non magnetic equipment, without sacrificing survey accuracy.
- A float valve is to be installed in the string.

- The combination of tortuous hole and high doglegs create a wellbore through which it may be difficult to pass casings and liners.

- The use of conventional rotary BHA with a RSS allow LWD and MWD sensors to be placed closer to the bit for better geosteering directional control.

- Drilling horizontal section in rotary mode allow for improved hole cleaning, resulting in less chance of mechanical and differential sticking.

3.2 Drilling BHA

3.2.1 Option 1 (Horizontal Drilling)

Table 2- 43: Recommended BHA for Drilling 6” Horizontal Hole (1)

Size	Description	No.	Comments
6”	Tricone Bit	1	
5”	Motor	1	
5.7/8”	S. Stabilizer	1	
4.3/4”	NMDC	1	
4.3/4”	LWD Tool	1	
4.3/4”	MWD Pulser	1	
4.3/4”	Crossover	1	
3.1/2”	Drillpipe		Number depends on the length of departure
3.1/2”	HWDP	26	
5.7/8”	HWDP	12	
6.3/8”	Drilling Jar	1	
6.3/8”	Crossover	1	
5.7/8”	HWDP	28	
5.7/8”	Drill pipe		Number depends on the length of departure

3.2.2 Option 2 (Horizontal Drilling)

Table 2-44: Recommended BHA for Drilling 6” Horizontal Hole (2)

Size	Description	No.	Comments
6”	PDC	1	
6”	RSS	1	
4.3/4”	NMDC	1	
4.3/4”	LWD Tool	1	
4.3/4”	MWD Pulser	1	
5.7/8”	S. Stabilizer	1	
4.3/4”	Drill collar	1	

Size	Description	No.	Comments
6”	S. Stabilizer	1	
4.3/4”	Drill collar	1	
4.3/4”	Crossover	1	
3.1/2”	Drill pipe		Number depends on the length of departure
3.1/2”	HWDP	30	
3.1/2”	Drilling Jar	1	
3.1/2”	HWDP	15	
5.7/8”	Crossover	1	
5.7/8”	HWDP	28	
5.7/8”	Drill pipe		Number depends on the length of departure

<u>Note:</u>

The use of special drilling equipment to drill the 6” horizontal hole, should be discussed thoroughly with the directional drilling and LWD representative ahead of time.

3.3 Special Tools

The following drilling tools/materials must be considered when applicable:

Table 2- 45: Special tools for drilling 6” horizontal hole

Tool	Main function	When to consider
Thruster	• Helps transfer weight to the bit in case of long horizontal	• BHA hanging problem • Buckling in drill string
Agitator	• Helps transfer weight to the bit, reducing drag and improving ROP	• Buckling in drilling string • Hanging BHA
AGS	• For minimizing tripping to change bent housing and sliding mode.	• Better ROP • Better hole cleaning
RSS	• Continuous steerable rotary drilling	• Low BUR
Lubricant	• For reducing torque and drag.	• Directional drilling problems

For more details refer to Chapter-2 “Special Drilling Operations” of Volume-2

3.4 Directional Challenges

The following table highlights the potential directional challenges associated with each formation during drilling the 6” hole.

Table 2- 46: Directional Challenges in Drilling 6” Horizontal Hole

Formation	Directional Issues
Shuaiba Units and Thamama Zone	• BHA’s Tendency to build/drop angle. • Difficulty to transfer weight to the bit when sliding due to buckling of the 3.5” Drillpipe. • Unpredictable walk rate in rotary mode. • Limited steering ability of PDC bits. • Build rate through dense limestone is less than expected (usually +/- 70% of expected). • Sliding to produce step downs in horizontal section is difficult due to buckling of the 3.5” drillpipe.

4. Drilling Optimization

- Drilling with steerable assemblies can create well bores far more tortuous than those drilled with conventional rotary assemblies.

- The combination of tortuous hole and instantaneous high doglegs create a well bore through which it may be difficult, and on occasion even impossible, to pass casing, liners production tubing.

- The horizontal section is drilled with an adjustable stabilizer controlled rotary assembly, there are no instantaneous doglegs, hole tortuosity is reduced and an improved well bore profile results. Because rotary build and drop tendencies take time to break, doglegs are reduced and are smoothed over long sections of the hole.

- The use of such a more conventional rotary assembly allowed LWD and MWD sensors to be placed closer to the bit for better geosteering directional control. Drilling the sections in rotary mode allowed for improved hole cleaning, resulting in less chance of mechanical and differential sticking.

5. Drilling Fluid

This section is drilled with KCL/XC Polymer mud and Low Solid Non-Dispersed mud. Non Damaging Fluid is required to reduce risk of barriers forming and also damaging invasion.

Mud System is typically slightly overbalance with the reservoir with a wall cake that requires little ‘draw down’ to lift off wellbore.

The NDF fluid used comprises brine or sodium chloride, no barite, no clays, a small amount of polymer for viscosity, starch for fluid loss and calcium carbonate to increase mud weight if necessary. Lubricants are also sometimes required to allow improved transfer of weight to the bit and sliding in the horizontal section.

Refer to Chapter-5 “Mud Guidelines” of this volume for more details.

6. Logging and Testing Requirements

- Testing is only performed in vertical pilot holes where there is some geological / model uncertainty. No testing is performed in deviated or horizontal oil production well unless there are special requirements.

- Generally the following logs are required in 6" horizontal hole.

Table 2- 47: Logs required for 6" horizontal hole

Hole Size	Formation Interval	Logs typically required
6"	Reservoir	LWD (Resistivity ,Density, Neutron, GR), FMI, MDT

7. Cleaning 6" Horizontal Hole

Cuttings settle by force of gravity along the low side of the hole forming a "bed" of solids.

Failure to achieve sufficient hole cleaning can cause severe drilling problems including: excessive overpull on trips; high rotary torque; stuck pipe; hole pack-off; reduced weight on bit leading to reduced ROP; formation break down and difficulty in running logs and coiled tubing. The most severe of these is sticking of the drill string.

Cutting transport is affected by numerous parameters:

- Rate of penetration

- In-situ fluid velocity in the annulus.

- Different particle size.

- Hole angle.

- Drilling fluid rheology
    - Pipe eccentricity, drill string positioned on the low side of the wellbore.
    - Hole volume circulation cycles.

- Drilling fluid velocity is the most important variable for cuttings transport. Cuttings bed are observed to form at inclination angles of more than 35°, and this bed can slide back down for angles up to 50°. Mud velocities in the range of 3 to 4 ft/s are necessary for high angles with no pipe rotation compared with the 1 to 2 ft/s normally used for vertical drilling.

- String eccentricity created by the drillpipe laying on the low side of the annulus, worsens the situation. Eccentricity diverts most of the mud flow away from the low side of the annulus, where the cuttings tend to settle, to the more open area above the drillpipe.

- The rheological characteristics of drilling fluids lead to a skewed flow distribution in the annulus for drill pipe that is eccentric in the hole when drilling deviated and horizontal wells. The shear thinning behaviour of the fluid, combined with the yield stress characteristics of the fluid do not favour flow in the restriction below the drill pipe. Optimizing the rheology of the fluid to minimize this effect is an important part of well planning and design.

- Periodic washing, reaming, back-reaming and wiper trips, wherein the drilling fluid is circulated, help to achieve satisfactory hole cleaning.

- For wells deviated higher than 35º, the best method to remove cuttings is by pumping thin fluids (e.g. water) in turbulent flow followed immediately by high viscosity / high weight pills. Keep the velocity constant while pumping to avoid packing off the hole.

- Improved efficiencies are possible when using weighted sweeps rather than high viscosity sweeps.

- Design BHA for minimum pressure loss in critical wells.

8. Potential Operational Hazards

Table 2- 48: Drilling Hazards in Drilling 6” Horizontal Hole

Potential Hazard	Hoe to mitigate
Stuck Pipe	• Minimize sliding intervals and periods and if possible keep pipe in rotation all the time. • Sweep hole with hi-vis pill at maximum flow rate as per hole condition dictates to avoid loading the annulus with cutting beds and consequently loss of circulation. • Turbulent or transitional flow is essential to maintain adequate removal of cuttings beds and hole cleaning. Use thin turbulent fluids with regular sweeping by high viscosity and high weight pills. • Watch torque, pressure and drag carefully while drilling horizontal hole • When the hole is packed off, jarring up is not the correct initial response and should be avoided. • If while POOH tight hole are encountered, do not exceed 30,000 lbs over pull, attempt to go back and circulate hole clean. • Control tripping speed (2min/stand) to avoid swabbing and formation mechanical damage.
Differential sticking	• Ensure preventative drilling practices are strictly adhered to i.e. moving and rotating drill-string as much as possible, minimizing length of unstabilised BHA. • Use spiral Drill Collars and HWDP.

Potential Hazard	Hoe to mitigate
	• Limit Mud Weight when drilling the reservoir objective to prevent build up of thick mud cake and potential for differential sticking across zones of differential pressure. • Minimize surveying time to avoid differential sticking.
Well Control	• Most of well control problems occur while tripping out due to swabbing (tripping speed) or failure to fill the hole with proper fluid volume; trip sheet has to be filled accurately and control tripping out speed to avoid well control problems.

9. Waste Management

Hole Size	Mud Salinity	Rental Equipment		Mud Handling	Cuttings Handling
6" H.H	Water Base Mud	**Tanks**	**4**	**NO DUMPING** Excess mud to be transported to injection disposal well.	Cuttings to be piled on location and to be used to bund the location.

- No waste pit should be dug, use a 300 bbls tank instead to collect waste mud and then transfer to waste tanks.
- Environment inspection checklist should be filled at least weekly and sent to office.
- Ensure discharge from sewage treatment unit meets ADNOC regulations.